Shell Canada Limited
2006 Annual Report

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Unless the content indicates otherwise, the terms Shell, Shell Canada, Shell Canada Limited, Corporation, Company, we, our and its are used interchangeably in this report to refer to Shell Canada Limited and its consolidated subsidiaries.

The terms Royal Dutch Shell and Royal Dutch Shell plc are used interchangeably in this report to refer to Royal Dutch Shell plc, which is Shell Canada's majority shareholder. The term Shell Group refers to the worldwide Royal Dutch Shell enterprise as a whole, including Royal Dutch Shell plc.

This annual report contains references to measures commonly referred to as non-generally accepted accounting principles (GAAP) measures. Additional disclosure relating to these measures can be found on pages 7 and 82.

This report contains "forward-looking statements" based upon management's assessment of the Company's future plans and operations. Forward-looking statements can be identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook.

The forward-looking statements contained in this report include references to anticipated growth and long-term profitability, future capital and other expenditures, organizational capability, the Company's plans for growth (including results of acquisitions), development, drilling, construction and expansion plans, estimates of capital costs, the viability and benefits of planned and future expansion projects, the timing of investment decisions, upgrading capacity, construction of common infrastructure, the impact of compression projects, the apportionment of pipeline capacity, the effects and benefits of the Company's technology, resources and reserves estimates, the timing for booking of additional reserves, future production of resources and reserves, oil and gas production levels, the submission and receipt of regulatory approvals, project costs and schedules, operational reliability, the quality and reliability of the Company's products and sales channels, emissions targets, safety targets, refining margins, market share, market conditions and Royal Dutch Shell plc's offer to purchase all of the common shares of the Company not already owned by it and its affiliates. Forward-looking statements of this nature are also contained in the Company's filings with Canadian and U.S. securities regulatory authorities.

Readers are cautioned not to place undue reliance on forward-looking statements. Although the Company believes that the expectations represented by such forward-looking statements are reasonable based on the information available to it on the date of this report, there can be no assurance that such expectations will prove to be correct.

Forward-looking statements involve numerous assumptions, known and unknown risks, and uncertainties that may cause the Company's actual performance or results to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, but are not limited to, the risks of the oil and gas industry (including operating conditions and costs), demand for oil, gas and related products, disruptions in supply, fluctuations in oil and gas prices, stakeholder engagement and the results of public consultations, project startup, schedules and execution, maintenance activities and schedules, market competition, labour availability, shortages of materials and equipment, constraints on infrastructure, the uncertainties involving the geology of oil and gas deposits and reserves estimates, including the assumption that the quantities estimated can be found and profitably produced in the future, the results of regulatory hearings, the receipt of regulatory approvals, the fulfillment of the Company's sustainable development criteria, the viability of the Company's processes and technology to improve operational efficiency and reduce the impact of its facilities and activities on the environment, fluctuations in foreign currency exchange rates, general economic conditions, the viability of the Company's financial plan, the ability to maintain an investment grade debt rating, commercial negotiations, changes in law or government policy, the risk that Royal Dutch Shell plc's offer will be unsuccessful for any reason and it will not be able to obtain the required approvals or clearances from regulatory authorities on a timely basis, if at all, and other factors, many of which are beyond the control of the Company. Readers should refer to the Management's Discussion and Analysis and Risk Management sections of this report for further discussion of the assumptions, risks and uncertainties identified by the Company.

The forward-looking statements contained in this report are made as of March 8, 2007 and the Company does not undertake any obligation to update publicly or to revise any of the forward-looking statements contained in this report, whether as a result of new information, future events or otherwise, except as required by law. The forward-looking statements contained in this report are expressly qualified by this cautionary statement.

Highlights

FINANCIAL HIGHLIGHTS	2006
Earnings ($ millions)[3]	1 738
Cash flow from operations ($ millions)[1,3]	2 614
Capital and predevelopment expenditures ($ millions)	2 426
Return on average common shareholders' equity (%)[3]	19.6
Return on average capital employed (%)[2,3]	18.2
Per common share (dollars)[3]	
Earnings – basic	2.11
Earnings – diluted	2.09
Dividends	0.440

OPERATING HIGHLIGHTS	2006
PRODUCTION	
Total hydrocarbon production (BOE/d)	214 900
Natural gas – gross (mmcf/d)	523
Ethane, propane and butane – gross (bbls/d)	19 800
Condensate – gross (bbls/d)	13 000
Bitumen – gross (bbls/d)	
Mining	82 500
In situ	12 400
Total bitumen	94 900
Sulphur – gross (long tons/d)	5 200
Crude oil processed by Shell refineries (m^3/d)	44 600
SALES	
Synthetic crude sales excluding blend stocks (bbls/d)	85 900
Purchased upgrader blend stocks (bbls/d)	35 400
Total synthetic crude sales (bbls/d)	121 300
Petroleum product sales (m^3/d)	47 300
PRICES	
Natural gas average plant gate netback price ($/mcf)	6.79
Ethane, propane and butane average field gate price ($/bbl)	33.94
Condensate average field gate price ($/bbl)	71.63
Synthetic crude average plant gate price ($/bbl)	61.32

[1] Cash flow from operations is a non-GAAP measure and is defined as cash flow from c working capital and operating activities (see page 7).

[2] Return on average capital employed is a non-GAAP measure and is defined as earn debt divided by the average of opening and closing common shareholders' equity plu short-term borrowings.

[3] Shell Canada adopted Emerging Issues Committee (EIC) Abstract 162 "Stock-Based C Retire Before the Vesting Date" with prior period restatement as required. (See Note 1 to

Commitments

SAFETY

- **The safety** of our operations and of everyone who works for the Company or visits its facilities is Shell Canada's top priority. The Company's safety target is zero harm to people.

COMPANY GOALS

- **Growth and profitability** are the Company's main goals within an overarching commitment to sustainable development. Pursuit of a strong and diverse portfolio of growth opportunities requires sizable capital investment funded by robust and profitable base businesses. Although the return on average capital employed may fall in periods of heavy investment, the resulting growth will support future, long-term profitability.

SUSTAINABLE DEVELOPMENT

- **Sustainable development** is the integration of economic, environmental and social considerations into the Company's day-to-day activities and future plans. Shell Canada aims to provide value to its customers in ways that respect environmental and social concerns while contributing to the economic benefit of its shareholders, employees and society at large.

OPERATIONAL EXCELLENCE

- **A focus on operational excellence** means that all employees are accountable for the aspects of costs and operations within their control. This includes the operational performance of every part of the Company in terms of plant reliability, project execution, health, safety and the environment, customer satisfaction and stakeholder engagement.

COMPLIANCE

- **Good corporate governance** is fundamental to the integrity and reputation of the Company. Policies and procedures are in place to foster compliance with applicable regulations governing every aspect of the Company's business. All Shell employees must conduct business in accordance with these policies and procedures and Shell's business principles and code of ethics, which may be viewed at www.shell.ca.

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Highlights

FINANCIAL HIGHLIGHTS	2006	2005 (restated)	2004 (restated)
Earnings ($ millions)[3]	**1 738**	2 001	1 283
Cash flow from operations ($ millions)[1,3]	**2 614**	3 036	2 125
Capital and predevelopment expenditures ($ millions)	**2 426**	1 715	951
Return on average common shareholders' equity (%)[3]	**19.6**	27.2	21.3
Return on average capital employed (%)[2,3]	**18.2**	26.7	19.9
Per common share (dollars)[3]			
Earnings – basic	**2.11**	2.43	1.55
Earnings – diluted	**2.09**	2.40	1.54
Dividends	**0.440**	0.367	0.313

OPERATING HIGHLIGHTS	2006	2005	2004
PRODUCTION			
Total hydrocarbon production (BOE/d)	**214 900**	228 700	219 700
Natural gas – gross (mmcf/d)	**523**	512	540
Ethane, propane and butane – gross (bbls/d)	**19 800**	23 300	25 100
Condensate – gross (bbls/d)	**13 000**	15 300	15 200
Bitumen – gross (bbls/d)			
Mining	**82 500**	95 900	81 300
In situ	**12 400**	8 900	8 100
Total bitumen	**94 900**	104 800	89 400
Sulphur – gross (long tons/d)	**5 200**	5 300	5 600
Crude oil processed by Shell refineries (m^3/d)	**44 600**	44 900	45 100
SALES			
Synthetic crude sales excluding blend stocks (bbls/d)	**85 900**	99 400	83 700
Purchased upgrader blend stocks (bbls/d)	**35 400**	37 100	38 200
Total synthetic crude sales (bbls/d)	**121 300**	136 500	121 900
Petroleum product sales (m^3/d)	**47 300**	49 100	47 500
PRICES			
Natural gas average plant gate netback price ($/mcf)	**6.79**	8.23	6.49
Ethane, propane and butane average field gate price ($/bbl)	**33.94**	34.79	28.71
Condensate average field gate price ($/bbl)	**71.63**	66.76	50.46
Synthetic crude average plant gate price ($/bbl)	**61.32**	57.55	44.67

[1] Cash flow from operations is a non-GAAP measure and is defined as cash flow from operating activities before movement in working capital and operating activities (see page 7).

[2] Return on average capital employed is a non-GAAP measure and is defined as earnings plus after-tax interest expense on debt divided by the average of opening and closing common shareholders' equity plus preferred shares, long-term debt and short-term borrowings.

[3] Shell Canada adopted Emerging Issues Committee (EIC) Abstract 162 "Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date" with prior period restatement as required. (See Note 1 to the Consolidated Financial Statements.)

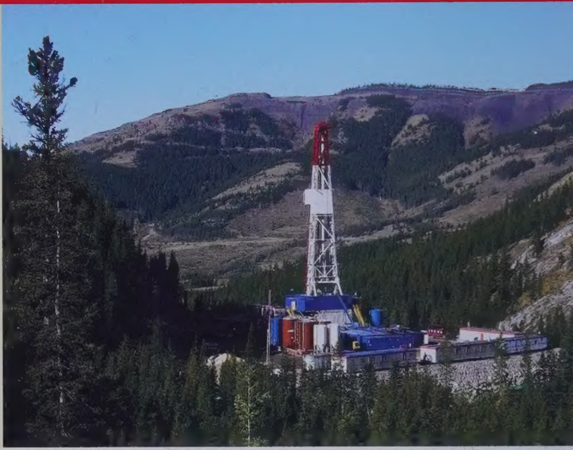
Results in 2006

- Strong earnings and cash flow from operations in 2006 were due mainly to production from the Company's Oil Sands and natural gas operations and record earnings in Oil Products. Shell Canada's return on average capital employed was 18.2 per cent.
- North American petroleum consumption remained high, despite high prices and increases in inventory levels. The average annual price of crude oil in 2006 was $66.20 US per barrel (West Texas Intermediate) compared with $56.56 US in 2005. Market differentials between light and heavy crude oil remained wide. Natural gas prices averaged $6.51 Cdn per thousand cubic feet in 2006 compared with $8.71 Cdn in 2005.
- Company share of Athabasca Oil Sands Project (AOSP) bitumen production averaged 82,500 barrels per day (bbls/d) down from 95,900 bbls/d in 2005. The reduction in production is due to the belt tear at the mine in the first quarter and the first major scheduled AOSP turnaround.
- Total average in situ production for 2006 was 12,400 bbls/d compared with 8,900 bbls/d in 2005. This production increase is attributed to new thermal production at Peace River and new volumes associated with the purchase of BlackRock Ventures Inc. (BlackRock).
- Total natural gas production in 2006 grew to 523 million cubic feet per day (mmcf/d) from 512 mmcf/d in 2005, more than offsetting natural field decline, due to increases from the Foothills and basin-centred gas businesses.
- Capital and predevelopment expenditures for 2006 amounted to $2,426 million (excluding the BlackRock acquisition), compared with $1,715 million in 2005.

Profile

EXPLORATION & PRODUCTION

The Exploration & Production (E&P) business unit explores for and produces natural gas and natural gas liquids, and is Canada's largest sulphur producer. E&P operates four sour natural gas processing facilities in the Foothills area of Alberta and a number of sour gas wells in northeast British Columbia, as well as an emerging basin-centred gas business (BCG) in the deep basin straddling the Alberta/British Columbia border. It also includes a 31.3 per cent share of the Sable Offshore Energy Project offshore Nova Scotia, an interest in the proposed Mackenzie Gas Project in Northern Canada and an exploration interest in the Orphan Basin offshore Newfoundland.



OIL SANDS

The Oil Sands business has operations in each of Alberta's three main oil sands deposits. The Athabasca Oil Sands Project's fully integrated operations include the Muskeg River Mine and extraction plant located north of Fort McMurray in northern Alberta and the Scotford Upgrader adjacent to Shell's Scotford Refinery near Edmonton, Alberta. Shell Canada holds leases in the Athabasca area estimated to contain about 10 billion barrels of bitumen in place. Shell's in situ operations include the Peace River Complex as well as additional operations near Peace River, Cold Lake and West Athabasca, acquired in 2006 from BlackRock Ventures Inc. (BlackRock).

OIL PRODUCTS

Oil Products manufactures, distributes and markets refined petroleum products across the country. The Oil Products business also procures crude oil and feedstocks for Shell's refineries in Montreal, Quebec; Sarnia, Ontario; and Fort Saskatchewan, Alberta. The refineries convert crude oil into various products, including gasoline, diesel fuel, aviation fuels, solvents, lubricants, asphalt and heavy fuel oils. The Company's Canada-wide network of 1,635 Shell-branded retail sites includes convenience food stores and car wash facilities.

At a Glance

Shell Canada Limited is a large integrated petroleum company in Canada comprising three business units supported by a number of corporate departments.

Achievements

- **EARNINGS** of $499 million
- **RETURN ON AVERAGE CAPITAL EMPLOYED** of 23.9 per cent
- **ACHIEVED YEAR-OVER-YEAR** natural gas production growth
- **MAJOR LAND ACQUISITIONS** in Alberta and British Columbia, and exploration licences offshore Newfoundland and Labrador
- **TWENTY WELLS DRILLED** in the BCG business and infrastructure construction underway

Looking Forward

- **EXPAND BCG PRODUCTION** targeting 100 mmcf/d by the end of 2007
- **SUSTAIN NATURAL GAS PRODUCTION** in the Foothills of Alberta
- **GROW NATURAL GAS PRODUCTION** and infrastructure in northeast British Columbia
- **EVALUATE ADDITIONAL OPPORTUNITIES** for Frontier investment
- **EVALUATE COAL BED METHANE PROSPECTS** in British Columbia

Achievements

- **EARNINGS** of $718 million
- **RETURN ON AVERAGE CAPITAL EMPLOYED** of 16.6 per cent
- **RECORD DAILY PRODUCTION RATES** achieved in the fourth quarter at Muskeg River Mine, Scotford Upgrader and the in situ business
- **ACQUISITION OF BLACKROCK**
- **FINAL INVESTMENT DECISION** and regulatory approval for AOSP Expansion 1

Looking Forward

- **CONSISTENTLY DELIVER** production from the existing integrated AOSP operations above the design capacity of 155,000 bbls/d through continued focus on reliability and improvements
- **DELIVER AOSP EXPANSION 1** on time and within the range of estimated costs
- **GROW BITUMEN PRODUCTION** through additional mining, in situ cold and thermal expansions
- **CAPTURE THE WHOLE VALUE CHAIN** by building upgrading capacity in line with increased bitumen production
- **CONTINUE TO DEVELOP NEW TECHNOLOGY** to support Oil Sands growth and improved operational performance

Achievements

- **RECORD EARNINGS** of $584 million
- **RETURN ON AVERAGE CAPITAL EMPLOYED** of 24.0 per cent
- **RECORD LIGHT OIL PRODUCTION**
- **COMMISSIONED** ultra low sulphur diesel projects
- **COMBINED ROAD TRANSPORT BUSINESSES** with Flying J in Canada

Looking Forward

- **MAINTAIN TOP PERFORMER POSITION** in Canada as measured by earnings per litre and unit costs
- **DETERMINE THE VIABILITY** of a new heavy oil refinery near Sarnia, Ontario
- **TARGET RELIABLE, EFFICIENT AND SAFE** manufacturing throughput at each of Shell Canada's refineries and lubricant plants
- **IMPROVE COMPETITIVE PERFORMANCE** by reducing and enhancing Shell-branded sales channels
- **DELIVER ON THE PROMISE** of the Shell brand by offering high-quality, differentiated fuels and lubricants

President's Message

March 8, 2007

CLIVE MATHER
President and Chief Executive Officer

Born in England, Clive Mather writes and speaks internationally on business, leadership and sustainable development. He is Chairman of the U.K. Government Corporate Social Responsibility (CSR) Academy and on the Board of Directors of the C.D. Howe Institute in Canada. He was a Director of Placer Dome Inc. until its takeover in January 2006. His career of 38 years with Shell has spanned all of its major businesses, including assignments in Brunei, Gabon, South Africa, the Netherlands and the United Kingdom. His last position was Chairman of Shell U.K. Limited, based in London. Clive Mather was appointed President and Chief Executive Officer of Shell Canada Limited from August 1, 2004.

Shell Canada delivered strong earnings during 2006, underpinned by record Oil Products results, growing natural gas production and solid oil sands production after the turnaround. The Company continued to focus on profitable growth through major projects in all of its businesses.

Other highlights of the year included improved safety performance with our lowest-ever injury rate, continued recruitment success and the successful commissioning of the ultra low sulphur diesel projects at the Montreal East and Scotford refineries, on time and on budget. The Company purchased BlackRock Ventures Inc. (BlackRock), the largest acquisition in our history, and announced the go-ahead of the Athabasca Oil Sands Project (AOSP) Expansion 1. During the year, the Company also acquired important, strategic land positions in oil sands (minable and in situ) and natural gas (both sweet and sour gas prospects). In Oil Products, a joint venture was signed with Flying J, which will transform the customer value proposition to the commercial road transport sector.

In October, Royal Dutch Shell announced its proposal to acquire all of the shares of Shell Canada that it did not already own. In January 2007, the Board of Shell Canada recommended the offer of $45 per share to the 22 per cent minority shareholders and, as we go to print, the outcome is not yet clear.

This is a very sensitive time for everyone. For many employees and retirees, the prospect of losing the status of a public company with an independent Board is an emotional one. On the other hand, the Royal Dutch Shell offer is a big vote of confidence in Canada and particularly in Shell Canada. There is no doubt that the people and assets of this company represent the potential for profitable growth for many decades to come.

Looking Forward

The Company's 2007 investment plan totals $4 billion, which is some 50 per cent higher than the previous year, excluding the acquisition of BlackRock. The plan is designed to support growth in unconventional oil and gas production, while maintaining the competitiveness of the downstream business.

Exploration & Production will continue to ramp up its basin-centred gas program, with target production of 100 mmcf/d by the end of 2007. The investment program also provides for ongoing exploration, including the Orphan Basin offshore Newfoundland, and positioning for access to the Klappan coal bed methane opportunity in British Columbia and the frontier gas basins, such as the Beaufort Sea and Labrador.

For Oil Sands, our prime goal is to continue growing production through operational excellence of the existing assets and by advancing growth projects. The biggest of these is the 100,000 barrel per day (bbls/d) AOSP Expansion 1. The in situ program includes development of a 100-well cold production program in the Peace River area, and the startup of the 10,000 bbls/d Orion steam-assisted gravity drainage (SAGD) project (Phase 1) near Cold Lake, Alberta. Together, these two projects will bring the Company's in situ bitumen production to more than 50,000 bbls/d by 2008.

As previously announced, Shell Canada has been examining the potential to maximize value from its growing oil sands production in Alberta through the expansion of its manufacturing infrastructure in Eastern Canada. To that end, Oil Products plans to spend $50 million in 2007 on predevelopment planning and engineering to determine the viability of a new heavy oil refinery near Sarnia, Ontario, capable of producing 150,000 to 250,000 bbls/d.

Conclusion

The Company has operated in Canada for 95 years, and during that time has generated enormous benefits for its shareholders, its many stakeholders and for society at large. The Shell brand is recognized across Canada for its commitment to customers, employees and sustainable development. Many competitors use Shell Canada as a benchmark – whether in safety, environmental management, career development or technology. And whilst the future ownership of the Company is not yet clear, the same focus on excellence will continue, whether Shell Canada remains a public company or becomes a full member of the Royal Dutch Shell business worldwide.

I want to extend my heartfelt thanks to my colleagues in the Company for their unstinting energy, enthusiasm and expertise. It has been a privilege to lead them over the recent years, as we have repositioned the Company for sustained growth, unimaginable a decade ago. The Senior Management Team has played a vital role in this, demonstrating leadership and vision. Their personal support has been exceptional. I want to equally thank my colleague directors on the Board, whose wisdom and encouragement have guided and supported the Company at a time of unparalleled challenge and opportunity. The Lead Director and members of the Special Committee deserve special recognition for their work in addressing the offer by Royal Dutch Shell and facilitating a joint recommendation. And finally, I would like to thank all our shareholders for their confidence in Shell Canada.

I wish them and you all the best for the future.

Clive Mather
President and Chief Executive Officer

March 8, 2007

Shell Canada's Senior Management Team

From left (standing):

David Brinley, *Vice President, General Counsel & Secretary;*
Cathy Williams, *Chief Financial Officer;*
David Fulton, *Vice President, Human Resources;*
Tim Bancroft, *Vice President, Sustainable Development, Technology and Public Affairs.*

From left (sitting):

Ian Kilgour, *Senior Vice President, Exploration & Production;*
Clive Mather, *President and Chief Executive Officer;*
Brian Straub, *Senior Vice President, Oil Sands;*
Paul Lapensée, *Director, Corporate Strategy;*
David Aldous, *Senior Vice President, Oil Products.*

Management's Discussion and Analysis

March 8, 2007

- *Growth*
- *Profitability*
- *Sustainable Development*

In this Management's Discussion and Analysis:

- All information is reported in Canadian dollars and in accordance with Canadian generally accepted accounting principles (GAAP) unless otherwise stated.
- Certain financial measures are not prescribed by Canadian GAAP. These non-GAAP financial measures do not have any standardized meaning and, therefore, may not be comparable with the calculation of similar measures for other companies. The Company includes as non-GAAP measures return on average capital employed, cash flow from operations, unit cash operating cost and total unit cost because they are key internal and external financial measures used to evaluate the performance of the Company.
- All forward-looking statements are qualified by the cautionary statement on the inside front cover of this report.
- The Corporation's reserves disclosure and related information have been prepared in reliance on a decision of the applicable Canadian securities regulatory authorities under *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities* (NI 51-101), which permits the Corporation to present its reserves disclosure and related information in accordance with the applicable requirements of the United States Financial Accounting Standards Board and the United States Securities and Exchange Commission (SEC). This disclosure differs from the corresponding information required by NI 51-101.

  If Shell Canada had not received the decision, it would be required to disclose (i) proved plus probable oil and gas reserves estimates based on forecast prices and costs and information relating to future net revenue using forecast prices and costs, and (ii) minable bitumen reserves estimates based on forecast prices and costs and information relating to future net revenue using constant and forecast prices and costs. The Corporation's internal and external, independent qualified reserves evaluators prepared the reserves estimates for 2006.
- References may be made to "recoverable" resources or resources "in place" that are inherently more uncertain than proved reserves or proved and probable reserves.
- Certain volumes have been converted to barrels of oil equivalent (BOE). BOEs may be misleading, particularly if used in isolation. A conversion of six thousand cubic feet of natural gas to one barrel of oil, as used in this report, is based on the energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Additional information relating to Shell Canada Limited filed with Canadian and U.S. securities regulatory authorities, including the Annual Information Form and Form 40-F, can be found online under Shell Canada's profile at www.sedar.com and www.sec.gov.

Financial Results

Shell Canada Limited earnings in 2006 were $1,738 million, down from $2,001 million[1] in 2005. Earnings were lower in 2006 due to the first major scheduled turnaround of the Athabasca Oil Sands Project (AOSP), which resulted in higher maintenance costs and lower production, and lower natural gas prices in the Exploration & Production (E&P) business. Earnings were positively impacted by higher oil prices and refining light oil margins, and a favourable adjustment in the second quarter of $222 million, primarily resulting from changes to federal and Alberta corporate tax rates. Total Long Term Incentive Plan (LTIP) charges were $44 million in 2006 compared with $186 million in 2005. Earnings in 2005 also included a favourable adjustment of $164 million related to the use of non-capital losses resulting from the acquisition of an affiliated company, Coral Resources Canada ULC.

[1] Shell Canada Adopted Emerging Issues Committee (EIC) Abstract 162 "Stock-Based Compensation For Employees Eligible to Retire Before The Vesting Date" with prior period restatement as required. (See Note 1 to the Consolidated Financial Statements.)

Selected Annual Financial Information

Year ended December 31

($ millions except per share data)	2006	2005	2004
		(restated)	(restated)
Earnings	**1 738**	2 001	1 283
Total revenues	**14 806**	14 394	11 285
Total assets	**17 556**	13 666	10 908
Total debt[1]	**1 435**	211	137
Per common share (dollars)			
Earnings – basic	**2.11**	2.43	1.55
Earnings – diluted	**2.09**	2.40	1.54
Cash dividends	**0.440**	0.367	0.313

[1] Total debt includes short-term borrowings, variable interest entity and medium-term notes. (See Note 6 to the Consolidated Financial Statements.)

Summary of Quarterly Results[1]

(unaudited)	2006					2005				
	Quarter				Total	Quarter				Total
($ millions except as noted)	1st	2nd	3rd	4th	Year	1st	2nd	3rd	4th	Year
EARNINGS										
Revenues	**3 449**	**3 748**	**4 028**	**3 581**	**14 806**	3 005	3 390	3 956	4 043	14 394
Expenses	**2 769**	**3 355**	**3 168**	**3 279**	**12 571**	2 454	2 669	3 320	3 184	11 627
Earnings before income taxes	**680**	**393**	**860**	**302**	**2 235**	551	721	636	859	2 767
Income tax	**229**	**(83)**	**272**	**79**	**497**	135	197	186	248	766
Earnings	**451**	**476**	**588**	**223**	**1 738**	416	524	450	611	2 001
SEGMENTED EARNINGS[2]										
Exploration & Production	**174**	**157**	**115**	**53**	**499**	136	119	147	263	665
Oil Sands	**121**	**111**	**265**	**221**	**718**	97	259	234	193	783
Oil Products	**155**	**205**	**202**	**22**	**584**	123	127	78	106	434
Corporate	**1**	**3**	**6**	**(73)**	**(63)**	60	19	(9)	49	119
Earnings	**451**	**476**	**588**	**223**	**1 738**	416	524	450	611	2 001
PER COMMON SHARE (dollars)										
Earnings – basic	**0.55**	**0.58**	**0.71**	**0.27**	**2.11**	0.50	0.64	0.55	0.74	2.43
Earnings – diluted	**0.54**	**0.57**	**0.71**	**0.27**	**2.09**	0.50	0.63	0.54	0.73	2.40
Weighted average shares (millions)	**825**	**825**	**826**	**826**	**825**	825	825	825	825	825
Dilutive securities (millions)	**10**	**9**	**8**	**9**	**8**	10	8	11	10	9

[1] Restated. (See Note 1 to the Consolidated Financial Statements.)

[2] Effective January 1, 2006, the Peace River business was transferred from Exploration & Production to Oil Sands. Prior period numbers have been adjusted to account for this transfer

Earnings for the fourth quarter of 2006 were $223 million compared with $611 million for the corresponding period in 2005. The decrease was mainly due to significantly lower natural gas prices, a $135-million charge for the Company's LTIP compared with a charge of $30 million for the same period in 2005, and a turnaround at Sarnia Refinery. Earnings in the fourth quarter of 2005 included a favourable adjustment of $65 million related to the use of non-capital losses from the acquisition of an affiliated company.

Total production for 2006 was 214,900 barrels of oil equivalent per day (BOE/d), down from 228,700 BOE/d in 2005. The decrease was mainly due to a belt tear at the mine in the first quarter and the scheduled turnaround at the mine and upgrader at mid-year, as well as lower natural gas liquids (NGL) production. Total hydrocarbon production for the fourth quarter increased to a record 244,900 BOE/d.

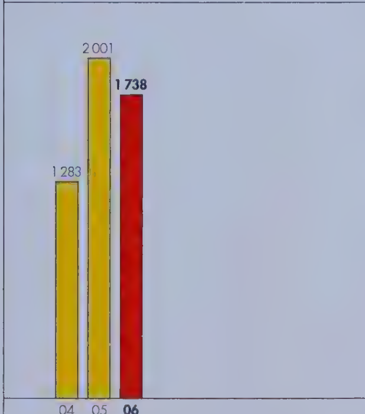
Reserves

At the end of 2006, gross proved natural gas reserves totalled 1,400 billion cubic feet (bcf) after production of 191 bcf, which compared with 1,592 bcf for 2005. Natural gas reserve additions from extensions and discoveries contributed 133 bcf of proved reserves but were offset by downward technical and economic revisions. The majority of the proved reserve additions is due to continued drilling success in basin-centred gas, which contributed an additional 95 bcf of proved reserves. The downward revisions were largely due to a reduction of 69 bcf recorded for the Tay River field following disappointing drilling results announced in November 2006.

At the end of 2006, gross proved NGL reserves were 61 million barrels. Production of 12 million barrels of NGL in 2006 was partially offset by net positive technical and economic revisions of two million barrels.

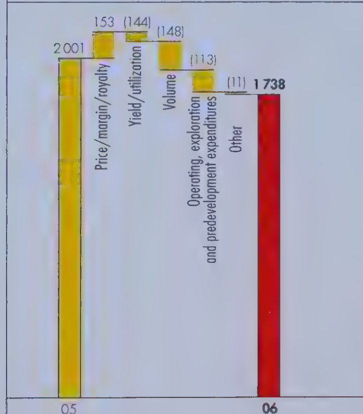
Earnings
($ millions)

Earnings were lower in 2006 due to the first major scheduled turnaround of the AOSP and lower natural gas prices.



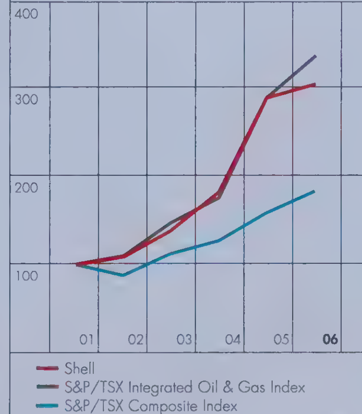
Earnings Analysis
($ millions)

Higher oil prices and refining light oil margins were offset by lower yield and utilization, lower oil production and higher expenses.



Total Shareholder Return
(index value)

Shell's five-year shareholder return continues to track well above the TSX Composite Index.



In 2006, gross proved minable bitumen reserves increased by 60 per cent to 1,292 million barrels from 808 million in 2005. Following the final investment decision for AOSP Expansion 1, the Company booked 497 million barrels on a gross basis to reflect the project's full economic life of 38 years. Drilling activity at the Muskeg River Mine resulted in the reclassification of 17 million barrels to the proved from probable category, offset by 30 million barrels of minable bitumen production. Total gross proved and probable minable bitumen reserves increased from 936 million barrels in 2005 to 1,695 million barrels for 2006.

The Company's gross in situ recovery bitumen reserves increased from 28 million barrels in 2005 to 96 million barrels in 2006, due mainly to the addition of 71 million barrels attributed to the acquisition of BlackRock Ventures Inc. (BlackRock). The requirement for the application of SEC regulations by Shell Canada limited the proved reserves that could be added in 2006 relative to the 2005 year-end bitumen position reported by BlackRock in accordance with Canadian reserves reporting regulations. Further reserves additions resulting from infill drilling in the Peace River field were offset by production of five million barrels, and minor technical and economic revisions.

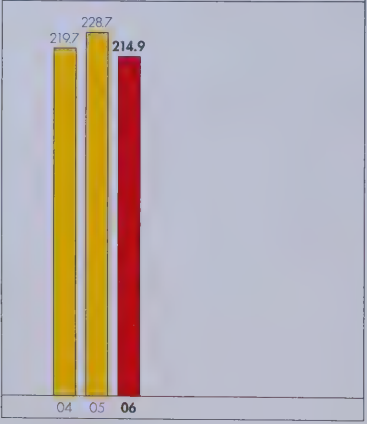
A detailed explanation of Shell Canada's reserves position appears on pages 80 to 85.

Shareholder Return

Total shareholder return in 2006 was 4.65 per cent. In the fourth quarter, the Company's quarterly dividend was $0.11 per common share, which was the same as the comparable period in 2005. Dividends paid for the year totalled $0.440 per common share, compared with $0.367 per common share for 2005.

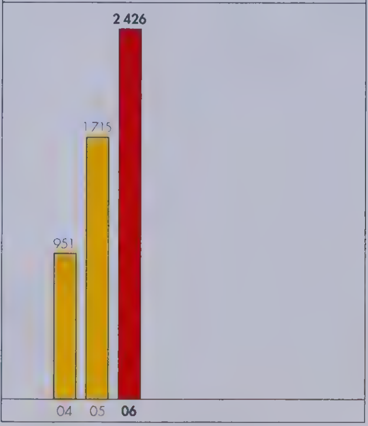
Total Hydrocarbon Production (thousands of barrels of oil equivalent per day)

Total production for 2006 was down slightly mainly due to a belt tear at the mine and the scheduled turnaround at AOSP.



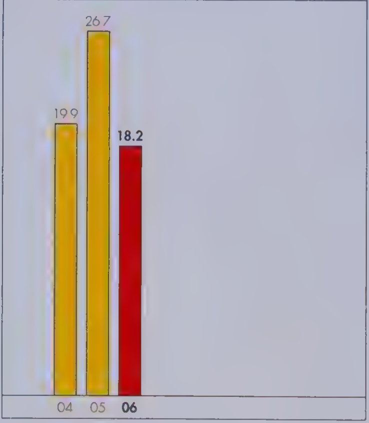
Capital and Predevelopment Expenditures ($ millions)

Total investment in 2006 increased in support of growth opportunities in unconventional oil and gas.



Return on Average Capital Employed (per cent)

Return on average capital employed remained well above 15% in a year of significant investment.



Business Environment

Despite prevailing high prices in 2006, North American petroleum consumption remained high. Crude oil prices were bolstered by strong demand for products, and apprehension caused by geopolitical concerns that threatened security of supply. In the first half of 2006, world oil inventories increased as companies chose to store oil in anticipation of potential supply disruptions. Crude oil prices reached record highs in 2006 with crude trading at a peak of $78.40 US per barrel in the summer and averaging $66.20 US per barrel for the year. Prices have since retreated from the summer highs, due in part to the removal of risk premiums associated with the anticipation of a strong hurricane season in the Gulf of Mexico and geopolitical issues. In sharp contrast to 2005, the hurricane season in 2006 was uneventful. Inventory built up to offset supply issues resulted in excess product, and the market appeared to ignore geopolitical issues at year-end as prices were weaker. As 2006 ended, OPEC supported crude prices by announcing reductions in production quotas while the market watched to see if the member countries would comply. Condensate pricing in Western Canada remained strong at average premiums of $3 US per barrel.

Although lower than 2005, natural gas prices remained relatively strong throughout the year despite bearish storage fundamentals. A record warm January with little heating demand led to a storage position at the end of March that was well in excess of the average. In addition, large volumes of gas went into storage by consumers fearing a repeat of 2005's hurricane season. The levels of gas in storage in the U.S. consistently set seasonal records throughout most of 2006. Gulf Coast gas production recovered from the damage of the previous year's hurricane season, while liquefied natural gas imports fell below the previous year's levels. Prices reached five-year lows through the month of September as hurricane season passed without significant incident. Year-end prices recovered due to seasonal-related demand. Demand for gas used in electrical generation facilities experienced year-over-year growth while industrial demand incurred some erosion due to the high prices at the end of 2005.

In 2006, the average natural gas price at AECO was $6.51 Cdn per thousand cubic feet (mcf) compared with $8.71 per mcf in 2005. At year-end, the price at AECO was $6.10 Cdn per mcf. The Company realized an average plant gate price of $6.79 per mcf in 2006, a decrease from $8.23 per mcf in 2005.

Natural gas liquids include ethane, propane, butane and condensate. Ethane supplies declined throughout 2006, while demand for its use in petrochemical products increased. Prices for ethane in 2006 tracked lower natural gas values. Both propane and butane prices retreated in 2006, as demand for these products moderated. Overall NGL processing margins were very strong, supported by firm crude and declining natural gas prices. The increase in Canadian heavy oil production increased demand for western condensate and butane supplies as a diluent in bitumen and heavy oil production.

Global sulphur demand has been relatively flat while production rose slightly in 2006. The current growth rate in Chinese sulphur consumption (four per cent per year) has fallen from past years' double-digit rates. Incremental cargoes were sourced from the Middle East and Kazakhstan. Shell Canada remains the leading sulphur exporter in Canada and was able to profitably remelt 352,000 tonnes from existing sulphur blocks to add to current production.

Health, Safety, Environment and Sustainable Development

Shell Canada believes that added business value from meeting the needs of its customers is best created by:

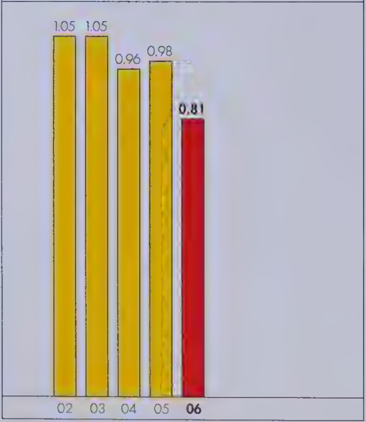
- achieving greater efficiency in the Company's use of energy and natural resources;
- proactively managing health, safety and environmental risks;
- benefiting local communities; and
- engaging with its stakeholders.

Shell Canada applies the principles of sustainable development to both existing operations and new business.

The Company has documented its environmental and social performance in its sixteenth annual *2006 Sustainable Development Report*, which will be available in April 2007 in print and online at **www.shell.ca**.

Total Recordable Injury Frequency
(per 200,000 hours)

The Company's overall safety performance, as measured by TRIF, was the best ever achieved in Shell Canada's history.



Managing Health, Safety and the Environment

Shell Canada relentlessly pursues the goal of no harm to people by assigning priority to the safety and well-being of its employees, contractors and neighbours. It was with profound regret that the Company learned of the death of a contractor at one of its well sites in September. The incident has since been formally investigated, with results of the investigation shared throughout the Company's businesses.

The Company's primary safety performance measure (total recordable injury frequency (TRIF) for employees and contractors) in 2006 was 0.81 injuries for every 200,000 hours worked, the best safety performance in Shell Canada's history and a significant decrease from 2005's 0.98 TRIF. While this improvement is heartening, considerable effort will continue to go into embedding health and safety expectations into the hearts and minds of all employees and contractors to complement Shell's extensive health, safety and environmental standards and processes.

Recognizing that personal injury statistics alone do not necessarily indicate how Shell Canada is managing its major hazards, the Company uses additional initiatives to focus on safety. Shell Canada has developed a formal process to assess the hazards at its facilities and ensure these hazards are safely managed. The Company has also developed methods to share valuable lessons from incidents in Shell Canada and industry, as well as new process safety measures that have already been implemented.

In June 2006, Shell Canada joined its Shell colleagues throughout the world to participate in Safety Week, an opportunity for all employees and contractors to work toward total elimination of injury incidents. Earlier in the year, consultants and leaders from across Shell Canada launched the first annual President's Safety Conference, a full day of discussions on industry best practices in health, safety and the environment. Also in 2006, the Company introduced several new tools into its safety portfolio, including upgraded safety footwear for workers at its facilities, and two safety videos featuring messages from Shell Canada's President and Chief Executive Officer.

The Foothills Operations team received the President's Safety Award in 2006 in recognition of its outstanding personal and process safety performance and overall approach to safety management. Foothills Operations distinguishes itself as having upheld this performance over many years, and currently maintains over 5.6 million hours without a lost-time incident.

Shell Canada continues to make progress towards its voluntary greenhouse gas emissions reduction target of six per cent below 1990 levels by 2008 for its base business (E&P and Oil Products), mainly through energy efficiency improvements. In 2006, greenhouse gas emissions from the base business were 7.9 million tonnes, 271,000 tonnes more than in 2005. Energy efficiency has improved by 1.1 per cent since 2000.

Benefiting Canadians

In 2006, Shell Canada donated over $9.2 million to not-for-profit organizations across the country to support environmental and educational programs as well as local communities where employees, retirees and marketing associates live and work.

Shell Canada matched funds raised by the employees and retirees of the Company and its affiliates for a donation of $3.6 million to the United Way of Calgary and Area. The Company's employees contributed $1.56 million to the campaign, exceeding 2005's contribution of $1.4 million. The Company matched employee and retiree donations for a total contribution of over $4.5 million across Canada.

In 2006, Shell Canada and the Nature Conservancy of Canada (NCC) announced a renewed commitment to the Shell Conservation Internship Program, a unique partnership between the two organizations that gives university and college students the opportunity to gain practical field experience on properties protected by NCC. The Company has committed $900,000 to the program over the next three years, in addition to the $1 million it has donated since the program was launched in 2002. Last year, 18 students chosen from nearly 700 applicants conducted conservation work, with projects ranging from bird studies and removal of invasive plants to teaching others about wildlife conservation.

The Shell Environmental Fund (SEF) provides grants to Canadians who want to improve or protect their local environment. In 2006, the SEF enhanced its commitment to the environment by increasing its budget to nearly $900,000 per year and supporting 250 environmental projects across the country. Grants support projects such as habitat restoration, waste reduction and recycling programs, educational initiatives and beach cleanups.

Engaging with Stakeholders

Shell Canada is committed to the principles of respect and transparency in its decision-making process and, in 2006, continued its emphasis on stakeholder consultation. Throughout the year, Shell representatives worked continuously with governments, industry organizations, non-governmental organizations, First Nations and local communities in project planning and operations.

The Company's dialogue and engagement with Aboriginal peoples exemplifies this commitment to stakeholder relations. In co-operation with First Nations elders living close to Alberta's oil sands operations, Shell Canada employees developed a program in 2006 to preserve knowledge about the use of traditional indigenous medicinal plants in the Athabasca region. A book containing a list and photos of these plants was published to document the ecological and cultural heritage of Aboriginal people in the region. In May, the Company sponsored young Inuvik delegates to attend a three-day National Aboriginal Capital Corporation Association Symposium in Vancouver. The conference invited entrepreneurial Aboriginal youth to share their knowledge and showcase their business skills. Also in 2006, Shell celebrated the tenth anniversary of its support for Actua, a national not-for-profit organization providing young Aboriginal Canadians with positive learning experiences in science, technology and engineering. The Company boosted its financial support of Actua by an additional $80,000 to become a Major Patron sponsor of Actua's Outreach program.

People

In 2006, the Company continued to grow and develop its workforce to support both its growth plans and significant retirement anticipated in the next few years. Nearly 700 new graduates and experienced hires joined the Company through the year.

Of particular note was the successful launch of the Campus Ambassador Program, which aims to strengthen and integrate recruitment and education investment activities at selected universities and colleges across the country. As well, the Company announced its largest single community investment ever in August 2006, committing $3 million to the Northern Alberta Institute of Technology's (NAIT) Building on Demand campaign. The investment will establish the Shell Manufacturing Centre on NAIT's campus and create $500,000 in trades bursaries and entrance scholarships for students pursuing apprenticeship and technical training in Edmonton, Alberta.

Shell Canada's reputation as an employer of choice was reinforced in 2006 with a number of national and international media rankings. Mediacorp Canada Inc. selected Shell Canada as one of Alberta's Top 25 Employers and, for the seventh consecutive year, one of Canada's Top 100 Employers, while the *Financial Post* included Shell Canada in its list of 10 Best Companies to Work For. In a survey of engineering students published in *Canadian Business*, Shell Canada was ranked in the top 10 workplaces in which students would most like to begin their careers.

Corporate Governance

Shell Canada's management and Board of Directors remain committed to the highest standards of corporate governance. The Company's principles, policies and standards provide a solid foundation for this commitment and enable Shell Canada to address evolving regulatory requirements and best practices in a timely manner. The Company regularly reviews this framework and its related practices in support of its corporate commitment.

In 2006, the Company focused on three key developments to its overarching corporate governance structure. In September, the Board appointed two additional independent Directors to expand the Board to 12 members. These new Directors, Louise Fréchette, O.C., and David Galloway, possess a wealth of valuable experience in government and business and will supplement the strengths and experience of the Company's other 10 Directors.

In October, the Company established an Ethics and Compliance Helpline as part of its overall financial, business, disclosure and anti-fraud controls and procedures. The Helpline was established to address questions related to ethics and compliance, and is accessible by employees, contract staff and Shell Canada customers, suppliers, contractors and agents.

In November, the Board elected to reconstitute the membership of its six committees. This reconstitution balances the more detailed committee activities among the nine independent Directors and creates a more efficient meeting schedule in which certain committee meetings can operate in parallel. All of the Board's committees are comprised of Directors who are independent of both Shell Canada and its majority shareholder. This reflects best practice in corporate governance, which has been the Company's long-standing approach.

Internal Controls

Shell Canada promotes strong financial, business, disclosure and anti-fraud controls and procedures in its business processes and maintains high standards of integrity in financial reporting. Management is responsible for establishing and maintaining adequate internal controls over financial reporting and, in accordance with Section 404 of the Sarbanes-Oxley Act (SOx), has evaluated the effectiveness of these controls based on the *Internal Control Framework – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management has concluded that the Company has maintained effective internal control over financial reporting as of December 31, 2006.

The Company's Chief Executive Officer and Chief Financial Officer have filed annual certifications for the last five years in compliance with SOx Section 302 and similar certifications required by Canadian regulation. These officers believe that Shell Canada's disclosure controls and procedures have operated effectively for the year ended December 31, 2006.

Risk Management

Each year, Shell Canada assesses areas of risk to which the Company is exposed in its operations and decides how to mitigate them to acceptable levels. The Board of Directors reviews the identified risks, which are consolidated for the overall Company. The areas of risk that apply to the entire organization are largely related to unprecedented growth opportunities and include: project execution in a heated competitive environment; control framework for growth; pre-emptive moves by competitors; potential adverse changes to tax regimes; organizational capacity; integration of new hires; reputation management; commodity prices; and climate change. Each business unit discusses the risks specific to its operations in its own section of this report.

PROJECT EXECUTION

Currently, Alberta's oil and gas industry is pursuing a number of concurrent large-scale projects, which compete not only to attract skilled employees but to procure materials and complete their engineering. Any or all of these constraints may increase costs and delay schedules. Shell Canada addresses these issues by assembling experienced project teams who share best practices and lessons learned through project look-backs, and by increasing the use of project management tools adopted from Royal Dutch Shell.

CONTROL FRAMEWORK FOR GROWTH

Without a strong business control framework and timely management information, large growth projects may suffer from higher costs and delays. The Company addresses this risk by obtaining the appropriate resources, training employees to ensure familiarity with the control framework and ensuring that there is a strong accountability framework in place. Management information systems continue to be developed to manage expenditures and to identify issues at an earlier stage. Additional actions include implementation of concerted project governance during project execution, management of capital plans with consideration of resource capability, a focused audit effort and appropriate leadership from Shell Canada's senior management team.

PRE-EMPTIVE COMPETITIVE FORCES

In a heated economy, strategic moves by Shell Canada's competitors may seriously weaken the Company's business advantage. Initiatives to counter this risk include the development of long-range strategies, as well as the use of third party resources during strategy development and a formal competitive review as part of the planning cycle.

TAX REGIMES

Adverse fluctuations in government tax regimes may take the form of increased royalties, a carbon tax, "windfall" profits tax, and reduced or eliminated government incentives, including those supporting frontier and alternative fuels initiatives. Shell Canada maintains its relationships with government through ongoing communication, as well as direct and indirect relationships with industry associations like the Canadian Association of Petroleum Producers and the Canadian Petroleum Products Institute, to ensure industry position is understood by the various levels of government.

ORGANIZATIONAL CAPACITY

Future growth will depend on the Company's ability to attract, develop and retain key people, including skilled craft labour and people for technical and project management roles. The experience level of new staff may also lead to reduced labour productivity. The Company addresses this risk by establishing recruitment targets for graduate and experienced staff, implementing comprehensive training and development programs and working closely with key contractors in support of their employee development activities. This has included, where necessary, international recruitment for skills not readily available in Canada and the import of temporary foreign craft labour. The Company also continues to strengthen its employee value proposition.

INTEGRATION OF NEW HIRES

Rapid business growth has required a large number of new hires who may not understand or embrace the Company's procedures and policies. Shell Canada introduces new employees to its corporate culture through an introductory "onboarding" program, and communicates regularly with new employees to reinforce its business and ethical principles. These activities are supported with mentoring programs for both graduates and new hires in many parts of the organization.

REPUTATION MANAGEMENT

Maintaining a competitive advantage in the oil and gas industry is a challenge. Shell Canada protects its reputation by continuously demonstrating and communicating its commitment to sustainable development, routinely monitoring the quality of its products, acting with integrity in all its operations, exercising its reputation management plan and reaching out to internal and external stakeholders.

COMMODITY PRICES

Fluctuations in the price of crude oil, natural gas and petroleum products have a significant bearing on the Company's financial results, as shown in the table below. Shell mitigates this risk by using conservative price premises for all capital projects and budgets. The Company also uses limited hedging in its Oil Products business to reduce exposure to price swings. However, Shell Canada does not generally hedge in light of its conservative premises and strong balance sheet.

CLIMATE CHANGE

Shell Canada shares the global concern about climate change and has been taking action to reduce greenhouse gas emissions. Federal and some provincial governments have announced plans to regulate these emissions by industry, with the specific requirements as yet unknown. However, the Company must expect tough targets, increased bureaucracy and higher costs. Because Shell Canada has been managing greenhouse gas emissions for over a decade, the Company is as well positioned as any company to manage this risk. Shell Canada is actively engaged in working to develop the related policy framework and regulatory structure through industry associations and directly with governments.

2006 Operating Earnings Sensitivities (annualized after-tax)[1]

		Increase/(Decrease)
EXPLORATION & PRODUCTION		
Natural Gas	10-cent US increase per million Btu (Henry Hub)	$ 9.7 million
Condensate	$1 US increase per barrel (West Texas Intermediate)	$ 2.8 million
Sulphur	$1 Cdn increase per tonne	$ 2.0 million
Foothills natural gas production	Increase of 10 mmcf/d	$ 8.6 million
OIL PRODUCTS		
Light oil sales margin	1/4-cent Cdn increase per litre	$ 25.0 million
Natural Gas	10-cent US increase per million Btu (Henry Hub)	$ (3.0) million
OIL SANDS		
Crude Oil	$1 US increase per barrel (West Texas Intermediate)	$ 41.6 million
Natural Gas	10-cent US increase per million Btu (Henry Hub)	$ (1.5) million
Equity Production	Increase of 1,000 bbls/d	$ 14.9 million
EXCHANGE RATE	1-cent improvement in $Cdn vs. $US	$ (24.7) million

[1] Sensitivities (eg: Henry Hub, West Texas Intermediate) are calculated independently and assume other market variables remain constant.

Exploration & Production

MANAGEMENT'S DISCUSSION & ANALYSIS

Over the past decade, Shell Canada's Exploration & Production (E&P) business strategy has focused on sustaining production and maximizing value from its established operations, notably those in the Foothills region of Western Canada. In more recent years, buoyant North American gas pricing allowed the Company to target new opportunities and augment its portfolio by adding lands in northeast British Columbia and in the Frontier and Unconventional Gas businesses. In 2006, E&P advanced this expanded approach, positioning its upstream portfolio for long-term growth while continuing to support its base business.

E&P delivered earnings of $499 million in 2006 compared with $665 million in 2005. Lower natural gas prices and natural gas liquids (NGL) production due to natural field decline were offset by lower Long Term Incentive Plan (LTIP) charges and a positive tax gain of $47 million, primarily from changes to federal and Alberta corporate tax rates. Total LTIP charges were $12 million in 2006 compared with $54 million in 2005.

The business unit's return on average capital employed for 2006 was 23.9 per cent, down from 40.3 per cent in 2005.

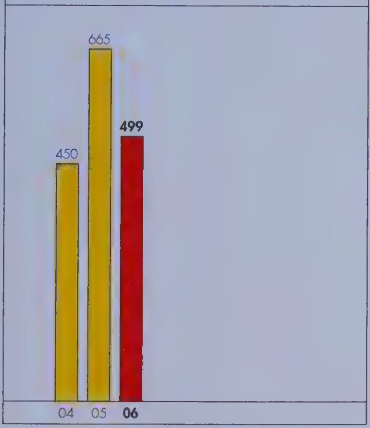
E&P's earnings in the fourth quarter of 2006 were $53 million compared with earnings of $263 million for the same period in 2005. The decrease in earnings was predominantly due to significantly lower prices, lower NGL volumes, a higher LTIP charge and higher dry hole write-off expenses.

Exploration & Production Highlights

($ millions except as noted)	**2006**	2005	2004
		(restated)	(restated)
Revenues	**2 200**	2 554	2 133
Earnings	**499**	665	450
Capital employed	**2 292**	1 884	1 550
Capital and predevelopment expenditures	**828**	796	435
Return on average capital employed (%)	**23.9**	40.3	29.2

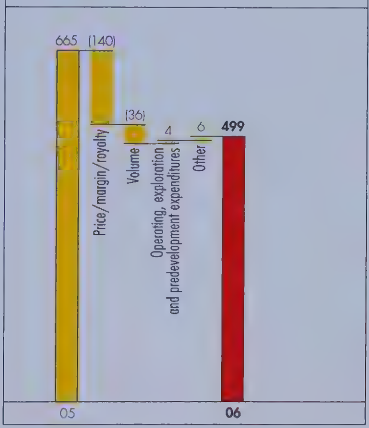
Exploration & Production Earnings ($ millions)

Earnings were down in 2006 due mainly to lower natural gas prices and NGL production.



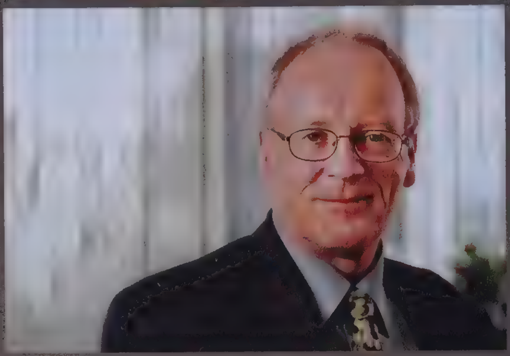
Exploration & Production Earnings Analysis ($ millions)

Lower natural gas prices and NGL production were offset somewhat by higher natural gas production in 2006.



Exploration & Production Unit Costs ($ per barrel of oil equivalent)

Unit costs were flat, year on year.



H. IAN KILGOUR
Senior Vice President, Exploration & Production

Ian Kilgour was born in England and graduated from the University of Southampton with a degree in Mechanical Engineering. After immigrating to Canada in 1975, he joined Shell Canada in 1976 and worked extensively in both the foothills and plains regions of Western Canada as well as offshore East Coast. He held various management positions in Shell Canada's exploration and production functions before being appointed Foothills General Manager in 1998. In 2002, Mr. Kilgour was named Senior Vice President, responsible for Shell's exploration and production business in Canada.

During 2006, the Company's E&P business acquired over 101,000 net acres at Crown land sales in Alberta and British Columbia as well as 247,000 acres in the Beaufort Sea. Also in 2006, E&P hired 145 new employees to continue growth in the business.

Total natural gas production in 2006 increased to 523 million cubic feet per day (mmcf/d) from 512 mmcf/d in 2005, with increases from the Foothills and basin-centred gas (BCG) businesses, more than offsetting natural field decline. Although commissioning of the Sable Offshore Energy Project (SOEP) compression facilities occurred in the fourth quarter, production in 2006 was adversely impacted by increased downtime associated with the installation and startup of the new facilities and by field and plant reliability issues.

Natural gas liquids production was 32,800 barrels per day (bbls/d) compared with 38,600 bbls/d in 2005, mainly due to natural field decline in Shell Canada's liquids-rich Caroline field.

Effective January 1, 2006, the Peace River business was transferred from E&P to the Oil Sands business unit. Prior period E&P earnings have been adjusted to exclude Peace River operations.

Foothills

The Foothills business continued to profit in 2006 from its focus on exploration, development, infrastructure optimization and operational excellence. Exploration in the business identifies prospects around existing infrastructure and prospective play areas in southern and central Alberta and northeast British Columbia, with the view to offsetting production decline and adding new reserves to Shell Canada's portfolio.

The Foothills business comprises operations in southern and central Alberta (with four Shell-operated gas plants and a number of producing fields) as well as producing fields in northeast British Columbia. Major activity in northeast British Columbia progressed in 2006 and into 2007 to tie in five wells, three of which were drilled in 2006. This activity includes construction of a major gathering system and dehydration facility at Wolverine River. Limitations in the main gathering system and processing facility will restrict gas sales from this region in the near term.

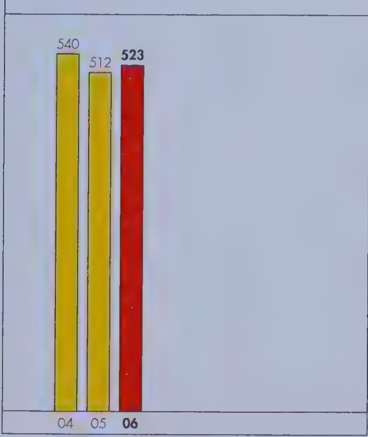
In 2006, Foothills natural gas production grew, in large part as a result of increases in production from the Tay River well southwest of Rocky Mountain House in central Alberta and initial production from northeast British Columbia. Sales gas production from the Foothills business averaged 397 mmcf/d of natural gas, making up 76 per cent of Shell's total natural gas production. The business produced 17,900 bbls/d of NGLs (ethane, propane and butane), 9,200 bbls/d of condensate and 5,200 tonnes per day of sulphur.

A well drilled in October 2006 to further appraise the Tay River Leduc structure confirmed the presence of natural gas at the drilled location; however, reef thickness at the site was considered insufficient for the well to be commercial. This information and ongoing tests on the Tay River discovery well have led the Company to revise downward its raw-gas-in-place estimates for the structure by more than 50 per cent to 220 billion cubic feet. A nearby exploration well targeting the Leduc formation was also unsuccessful.

In mid-2006, Shell Canada announced its decision to reconfigure its Waterton gas plant in southern Alberta. Some existing equipment at the 44-year-old asset, including one of the facility's two processing trains, will be decommissioned and more energy-efficient equipment installed. Detailed engineering and planning work on this optimization project is ongoing. Shell Canada expects to begin construction of the Waterton optimization project in March 2007, with completion in early 2008. The investment should lead to significantly reduced operating costs and environmental improvements, including reduced fuel gas use and reduced greenhouse gas and stack-top emissions.

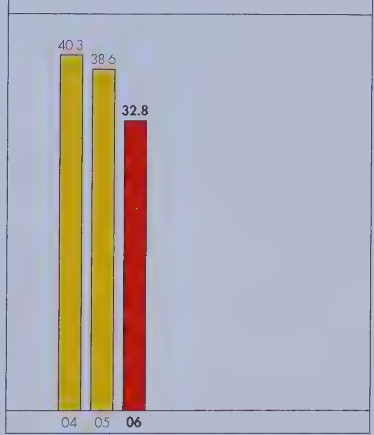
Gross Production of Natural Gas
(millions of cubic feet per day)

Total natural gas production increases came from the Foothills and basin-centred gas (BCG) businesses.



Gross Production of Natural Gas Liquids
(thousands of barrels per day)

Natural field decline in the liquids-rich Caroline field contributed to the continued decline in NGLs.



A key technological component of Shell Canada's strategy for sustainably developing its BCG fields is pictured here. Located approximately 95 kilometres southwest of Grande Prairie, Alberta, in the Chinook Ridge area, this well site allows the Company to drill up to four directional wells from a single "pad." Using pad drilling instead of drilling individual well sites results in less habitat disturbance and the creation of fewer pipeline right-of-ways and new roads.

Unconventional Gas

E&P's Unconventional Gas business focuses on BCG opportunities in the deep basin straddling the Alberta/British Columbia border, and on coal bed methane (CBM) prospects in north-central British Columbia.

The year 2006 represents the first full year of production for Shell Canada's BCG business. While progress on the drilling program was very encouraging, production was constrained to approximately 20 mmcf/d by restricted access to local gathering and processing facilities. A line loop project designed to debottleneck some of the existing gathering system constraints in the area was completed early in the year, and assisted in improving production capability to 28 mmcf/d by year-end. For future processing requirements, Shell Canada has contracted for capacity in the expanded Elmworth Plant to secure 150 mmcf/d of firm processing capacity over a 20-year period. Construction of a compressor station and a jointly owned 58-kilometre pipeline to transport gas to the Elmworth Plant is underway. These facilities are expected to be completed and operating by the end of 2007.

Drilling results in the BCG play are strong. Five exploration wells were drilled and tested in 2006 with a success rate of 80 per cent. Including outside-operated wells, the BCG business participated in a total of 20 wells in 2006. Initial rates on the new wells in Shell's core area of Chinook Ridge continue to be above average for the region. Downspacing approval from the Alberta Energy and Utilities Board to drill four wells per section in the Nikanassin formation in the Chinook Ridge/Narraway region was received late in 2006. The program is currently supported by five Shell-operated rigs dedicated to the BCG play, as well as additional outside-operated rigs. Production is targeted to reach 100 mmcf/d by the end of 2007.

In 2006, the Company's BCG land base expanded by an additional 84,000 net acres to a cumulative 268,000 net acres.

Shell Canada's CBM test well program in the Klappan area of northeast British Columbia was postponed in 2006 to allow time for further public consultation with local communities. The Company holds rights to nearly 800,000 net acres of land in this prospective area and three wells were drilled in 2004.

Frontier

SABLE OFFSHORE ENERGY PROJECT

Production from the SOEP fields in the shallow water offshore Nova Scotia continues to provide the Company with substantial cash and earnings, accounting for 20 per cent of Shell Canada's natural gas production. Sales gas volumes from SOEP averaged 107 mmcf/d (Shell share) in 2006 compared with 119 mmcf/d in 2005. This decrease was due mainly to normal field decline and higher downtime, in part owing to the installation of the compression project.

The SOEP compression platform commenced operation during the fourth quarter of 2006. This project is expected to increase Shell Canada's share of SOEP production to approximately 140 mmcf/d in 2007, and will help increase recovery from SOEP in the medium term. SOEP production decline was also partially offset by a successful third well in the Alma field drilled during 2006 and by the contribution of an infill well in the Venture field, which commenced production in late 2005.

OTHER EAST COAST OFFSHORE INTERESTS

Shell Canada has a 20 per cent interest in eight exploration licences in the Orphan Basin offshore Newfoundland and Labrador. These interests were obtained by farm-in during 2005. The outside-operated Great Barasway exploration well, the first to be located in the deep water Orphan Basin, was spudded in August and continued drilling into the first quarter of 2007. Results from this well will assist in the planning of further drilling and seismic activities for 2007.

Northern Canada

The Mackenzie Gas Project team participated in the National Energy Board (NEB) and Joint Review Panel (JRP) public hearings, which started in January 2006. The NEB largely concluded its scheduled hearings as planned in December 2006. The JRP public hearing process has been extended, in part due to a federal court ruling in November. Its earliest completion will now be in the second quarter of 2007.

The project has released an updated cost and schedule estimate in early 2007. The cost of the total project (three anchor fields, gas gathering system and pipeline) is now estimated at approximately $16 billion (2006 $). The updated project schedule would see potential project startup no earlier than 2014. This cost estimate reflects the escalation being experienced by all major capital-intensive energy projects, as well as an improved understanding of the costs associated with developing extensive infrastructure in the more remote areas of the North. The 2014 startup date is contingent upon the project proponents gaining sufficient confidence in the project's viability to proceed in the near term with detailed engineering and execution planning.

Cost increases and remaining regulatory and permitting uncertainties present a significant challenge to the project's viability. Current work efforts are focused on completing the regulatory hearings, obtaining an appropriate fiscal framework for this basin-opening pipeline, advancing potential shipping agreements with other producers and completing the remaining benefits and access agreements with Aboriginal groups. Decisions regarding the future pace of spending for the project will be influenced by progress in all of these areas.

Shell Canada was the successful bidder for offshore oil and gas exploration rights in the ND-2 block in the Beaufort Sea, approximately 200 kilometres northwest of Inuvik. Shell Canada has a long-standing commitment to the North, and this acquisition is consistent with the Company's goal of building a long-term strategic land base in Frontier basins.

West Coast Offshore Canada

The Company continues to be the largest landholder in this highly prospective basin with 12.8 million net acres of land. The area has been subjected to a moratorium since 1971.

Health, Safety and Environment

The death of a contractor at one of E&P's well sites in September 2006 was a tragic accident that deeply saddened Shell Canada people. Alberta Occupational Health and Safety subsequently led an investigation into the cause of the fatality, with the Company's full support, and results of that investigation have since been shared throughout Shell Canada's businesses.

This incident overshadowed the business's overall safety performance results, which otherwise were the best ever recorded in its history. In 2006, E&P reported a safety achievement of 1.0 recordable injuries for every 200,000 hours worked, compared with a rate of 1.08 in 2005. Shell Canada's Foothills business achieved more than four million hours without a lost-time incident in 2006. This milestone was achieved in the context of a broad spectrum of work environments, both in the field and office.

E&P's Operations Integrity Assurance program has provided the focus for ensuring compliance to process safety priorities and operational efficiency. This program has been developed over several years and is in use at all of E&P's operating complexes. The initiative, which is currently being further upgraded, is complemented by adherence to a formal competency assurance program for operating staff.

An important component of Shell Canada's commitment to sustainable development is E&P's reduction of energy usage at its facilities. In 2006, the Company commenced construction to prepare for installation of a steam turbine-driven generator in 2007 capable of converting excess steam to electricity at its Caroline facility. The generator is designed to convert 5,000 tonnes/day of steam to approximately 18 megawatts, almost enough to power the Caroline facility. The amount of power actually generated will depend on the total volume of gas processed at Caroline as well as its specific composition.

Minimizing the impact of drilling operations on wildlife by operating at times that avoid seasons critical to wildlife is a priority for E&P. The Company seeks to gain information that allows improved planning and contributes to a better understanding of the potential impacts in the areas it operates in, by sponsoring original research in these areas. E&P pursues opportunities to work with universities, environmental non-governmental agencies and other corporations to collaborate and share resources. In 2006, Shell Canada led or participated in a number of environmental studies, including an analysis of wolf predation upon threatened Woodland caribou and other species in west-central Alberta, initiation of a five-year study of elk ecology in southwest Alberta, and contribution to a long-term biodiversity program to assess a wide range of species in selected areas of Alberta.

All E&P operating sites are registered to a global ISO 14001 standard of environmental management, which requires demonstrated compliance with environmental legislation and continuous improvement in environmental performance. Numerous expiring certificates at Shell's upstream facilities were reregistered in 2006.

Looking Forward

In the year ahead, E&P will maintain its focus on operational excellence in the existing operations while growing its natural gas production and infrastructure with continued investment in northeast British Columbia and BCG, and evaluating new opportunities in coal bed methane and the Frontier basins.

2007 Capital and Predevelopment Investment

E&P's planned investment program for 2007 is $1,070 million, of which approximately $430 million will support exploration activities and $640 million will support development, an increase of approximately 25 per cent over 2006. About 60 per cent of the E&P program is focused on growth opportunities, including $470 million for unconventional gas, $110 million for Frontier opportunities, and nearly $40 million for predevelopment expenses pertaining to the Mackenzie Gas Project. The balance of the program is directed to sustaining natural gas production levels in the foothills area of Western Canada and at SOEP.

Risk Management

ACCESS TO LAND

Failure to establish and maintain successful relationships with First Nations, governments, environmental non-governmental organizations and other stakeholders may lead to lost or curtailed access to Crown and frontier lands. The Company has increased its internal capacity to actively engage with stakeholders in order to meet or exceed consultation standards.

INFLATIONARY ENVIRONMENT

With extremely high industry activity levels, demand for many goods and services created an environment of high inflation and supply assurance concerns. Although widespread throughout the business, this pressure was particularly evident in large capital projects and plant turnarounds. Shell Canada's supply chain management organization and the drilling organization have adopted measures such as making firm commitments to secure pricing and supply, selectively increasing long lead inventory items and leveraging long-term supplier relationships to help mitigate the full impact of this current inflationary environment.

Oil Sands

MANAGEMENT'S DISCUSSION & ANALYSIS

Oil Sands earnings in 2006 were $718 million compared with $783 million in 2005. Higher oil prices were offset by lower production due to the belt tear at the mine in the first quarter of 2006 and the first major scheduled turnaround of both the Muskeg River Mine and the Scotford Upgrader in the second quarter. The 2006 results included a favourable tax adjustment of $144 million, primarily resulting from changes to federal and Alberta corporate tax rates. Total Long Term Incentive Plan (LTIP) charges were $8 million in 2006 compared with $30 million in 2005.

Oil Sands earnings in the fourth quarter of 2006 were $221 million, up from $193 million for the corresponding period in 2005. Increased in situ production, lower heavy oil differentials and an improved Athabasca Oil Sands Project (AOSP) synthetic product mix were only partially offset by lower crude prices and an LTIP charge of $29 million in the quarter. Earnings for the quarter also include a $21-million gain from AOSP Expansion 1 payments received from the other joint venture owners and an insurance settlement of $15 million from the June 2006 fire at the BlackRock Seal battery.

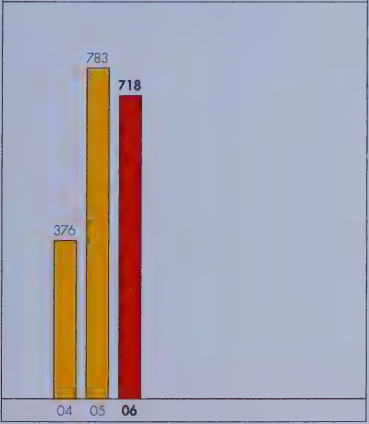
The Company's share of AOSP bitumen production in 2006 averaged 82,500 barrels per day (bbls/d), down from the 95,900 bbls/d achieved in 2005. The reduction in production was due to the belt tear at the mine in the first quarter and the first major scheduled AOSP turnaround in the second quarter. In the fourth quarter of 2006, the Company's share of average AOSP bitumen production was 106,600 bbls/d compared with 106,800 bbls/d for the same period in 2005.

Oil Sands Highlights

($ millions except as noted)	**2006**	2005	2004
		(restated)	(restated)
Revenues	**3 363**	3 356	2 164
Earnings	**718**	783	376
Capital employed	**5 982**	2 680	2 832
Capital and predevelopment expenditures	**1 150**	420	195
Return on average capital employed (%)	**16.6**	27.8	12.5

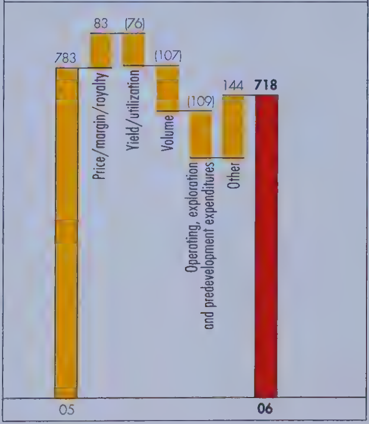
Oil Sands Earnings
($ millions)

Higher oil prices were offset by lower production due to the belt tear at the mine and the first major scheduled turnaround at AOSP.



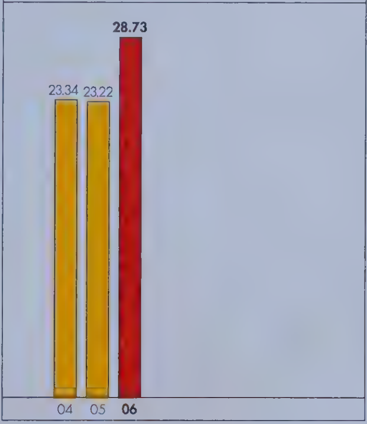
Oil Sands Earnings Analysis
($ millions)

Higher oil prices and a favourable tax adjustment of $144 million were offset by lower production and increased costs.



Oil Sands Mining Unit Cash Operating Cost
($ per barrel of oil equivalent)

The belt tear at the mine and the AOSP turnaround impacted unit costs.



BRIAN E. STRAUB
Senior Vice President, Oil Sands

Born in Alberta, Brian Straub holds a Petroleum Engineering degree from the University of Wyoming. He joined Shell Canada in 1977 and has held various drilling and operating, technical, and commercial management positions in Shell Canada's oil and natural gas business. He has also worked with Royal Dutch Shell plc's global operations on assignments in Oman, Brunei and Singapore. Most recently, he was Vice President, Technical for the Asia Pacific region and worked on several world-class projects such as Changbei in China, Pohokura in New Zealand, as well as offshore and deep water projects in Brunei and Malaysia. Brian Straub was appointed Senior Vice President of Shell Canada's Oil Sands business effective October 1, 2005.

Unit cash operating costs for the AOSP averaged $28.73 per barrel in 2006, an increase of $5.51 per barrel compared with 2005. The increase was largely due to the first major scheduled AOSP turnaround, which resulted in higher maintenance costs and lower production. Unit cash operating costs in the fourth quarter of 2006 were $24.26 per barrel compared with $23.88 for the same period in 2005. The Company realized an average synthetic crude price of $55.56 for the quarter.

Total average in situ production for the full year was 12,400 bbls/d compared with 8,900 bbls/d in 2005. In situ production for the fourth quarter was 20,400 bbls/d. Up significantly from 8,900 bbls/d in the fourth quarter of 2005, this production is attributed to new thermal production at Peace River and new volumes associated with the purchase of BlackRock Ventures Inc. (BlackRock).

Operations

The AOSP completed its first major scheduled turnaround at the Muskeg River Mine and the Scotford Upgrader in 2006. Despite the maintenance costs and lower production associated with this turnaround, the Oil Sands business, including the in situ assets, reported strong operational performances in 2006.

AOSP MINING AND UPGRADING

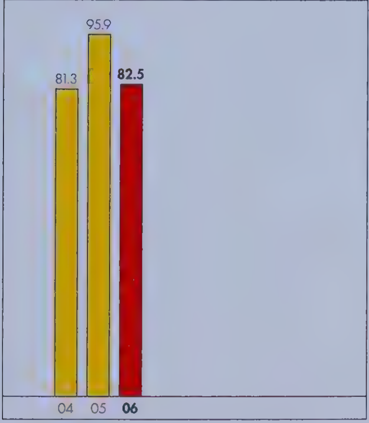
The average total bitumen production at the Muskeg River Mine for the year was 137,500 bbls/d, below the design rate of 155,000 bbls/d and compared with 159,900 bbls/d in 2005. The mine produced 30 million barrels of bitumen (Shell share) in 2006 compared with 35 million barrels in 2005 and 30 million barrels in 2004.

In late February 2006, a tear in the conveyer belt that carries ore from the crushers in the mine to the bitumen extraction plant reduced operations to a single train at both the mine and the upgrader. A full shutdown of the mine was required to install a new belt on March 14, and both the mine and upgrader were returned to full design rates by March 20. A root cause analysis of the conveyer belt tear was conducted, and changes in the maintenance practice and belt operating procedures have been implemented.

Oil Sands Mining Gross Bitumen Production

(Shell share) (thousands of barrels per day)

Production was impacted by the belt tear at the mine and the AOSP turnaround.



Planned maintenance work at the Muskeg River Mine and the Scotford Upgrader began in May 2006 and was extended to run through late June, with full resumption of production rates in mid-July. Following initial cleaning and inspection of mine and upgrader equipment, a decision was made to undertake additional maintenance and repair work at both sites. The turnaround, which employed over 4,000 maintenance workers at its peak, was the largest in Shell Canada's history.

After resumption of full operations in July, both the mine and upgrader have consistently produced above-design capacity and both have set new daily production records in the fourth quarter.

IN SITU

Shell Canada has operated in situ assets since 1979, when the Company began production at its Peace River Complex in northern Alberta. Effective January 1, 2006, the Peace River business was transferred from Shell Canada's Exploration & Production business to its Oil Sands unit. In 2006, Shell Canada also gained significant new in situ resources and additional production through its acquisition of BlackRock. Synergies between the Company's in situ, mining and upgrading and BlackRock's oil sands operations are expected to provide opportunities for reduced costs and larger-scale heavy oil integration.

The Hydrocyclone Pilot Project at the AOSP's Muskeg River Mine is a new technology option that may eventually help process lower-grade ores and de-sand bitumen. Testing is ongoing and results are being carefully monitored in hopes the technology may provide an alternate bitumen extraction and conditioning process, and a way to access part of the Company's bitumen currently considered unrecoverable. Preliminary results on phases 1 and 2 of this technological innovation have been encouraging, with the process demonstrating improved recovery.

Following a successful drilling program and integration of BlackRock volumes, 2006 overall in situ bitumen production averaged 12,400 bbls/d compared with 8,900 bbls/d in 2005. At Peace River, new thermal production came onstream in the third quarter from two well pads.

Shell Canada achieved record production rates in excess of 25,000 bbls/d bitumen from its in situ operations in November, and now has the capacity for 30,000 bbls/d. However, in situ production was impacted in 2006 by a scheduled facility turnaround at Peace River, a fire at the Seal battery in June and more recently the apportionment on the Rainbow Pipeline, which transports bitumen to market.

Growth

MINING AND UPGRADING

Since the launch of integrated operations in 2003, Oil Sands' performance has provided Shell Canada with a strong base from which to expand.

Following an extensive feasibility study, cost estimate and assurance review process, the Company issued its formal expansion proposal to the AOSP owners for the AOSP Expansion 1, a fully integrated 100,000 bbls/d (60,000 bbls/d Shell share) expansion of oil sands mining and upgrading facilities. Beyond AOSP Expansion 1, Shell Canada plans additional oil sands expansions that could potentially increase gross minable bitumen production to approximately 770,000 bbls/d. Bitumen upgrading capacity could also be increased to about 700,000 bbls/d through a series of Shell Canada-owned upgrader projects.

In 2006, Shell Canada received the regulatory approvals needed to proceed with AOSP Expansion 1. The first bitumen recovery from AOSP Expansion 1 is expected in the fourth quarter of 2009 with synthetic crude production from the Scotford Upgrader following in late 2010.

Expansion 1 at the mine includes mining and bitumen extraction from the Jackpine mine area integrated with the base Muskeg River Mine processes for bitumen cleaning and expanded utilities. Site preparation and installation of access roads, and excavation of deep underground utilities including positioning of cables, electricity and sewers, progressed steadily through 2006. Environmental stewardship, including water management and protection, and fishery and wildlife protection, is a key area of focus for these construction activities.

AOSP Expansion 1 also involves the addition of a third bitumen upgrading train at the Scotford Upgrader, which will increase total upgrading capacity by 100,000 bbls/d. Site preparation, including preliminary fieldwork and the installation of deep underground facilities, is underway.

IN SITU

In July 2006, the Company announced its intention to build on its expanded in situ portfolio, using a variety of production techniques to obtain its long-term potential of 150,000 bbls/d in situ production. With the acquisition of BlackRock, Shell Canada acquired access to significant additional resources at Athabasca, Peace River and Cold Lake, substantially augmenting the Company's overall oil sands portfolio.

Following the acquisition, BlackRock's Peace River assets were integrated with Shell Canada's existing operations and development plans. Maintaining BlackRock's stated growth plan and capital investment program, construction on the 10,000 bbls/d first phase of the Orion steam-assisted gravity drainage (SAGD) project near Cold Lake continued in 2006. The smaller, non-strategic Lloydminster-area assets Shell Canada acquired as part of the BlackRock acquisition were sold in the fourth quarter of 2006.

At Peace River, regulatory applications were filed to increase production from the existing capacity of 12,000 bbls/d to more than 100,000 bbls/d in the long term. Shell Canada intends to increase bitumen production across its Peace River leases using cold (primary) production followed by thermal (horizontal cyclic steam) techniques to increase bitumen recovery. Drilling for the initial phase of cold production is expected to begin in early 2007, with a final investment decision on the first 50,000 bbls/d thermal phase expected post regulatory approval, as early as 2008. Cold production involves producing bitumen without steam injection. Previous delineation drilling has indicated that some areas within Shell Canada's leases may contain bitumen that is mobile and can be produced using this primary recovery method.

Shell Canada has options to participate in additional in situ developments with Chevron Canada Limited and Western Oil Sands L.P. In 2006, the Company exercised its right to acquire a 20 per cent working interest in Chevron Canada's Ells River in situ leases, located approximately 50 kilometres northwest of Fort McMurray. Delineation drilling commenced during the winter of 2006/2007.

Health, Safety, Environment and Sustainable Development

In 2006, Oil Sands recorded its best-ever lost-time injury frequency rate of 0.02 per 200,000 hours worked by focusing on personal responsibility for safety and the task at hand. The Muskeg River Mine reported four million hours without a lost-time incident (LTI) in early January 2007, while the Scotford Upgrader achieved over four million hours without an LTI in late 2006. Oil Sands' total recordable injury frequency rate was 0.79 per 200,000 hours worked.

The AOSP introduced a number of new safety programs throughout the year. The Scotford Upgrader implemented a Worker Observation Program incorporating over 400,000 work site observations by safety specialists and managers. The program allows observers to engage employees in an open manner to talk about safe behaviours on the job. At the Muskeg River Mine, a Barrier Elimination Support Team was introduced to train employees to become acutely aware of risk-taking behaviours, and to encourage them to look for potential safety hazards in the workplace.

Oil Sands will increase its focus on process safety in 2007. Significant internal and third-party process safety incidents will be analyzed to identify and implement improvements. Furthermore, the introduction of the Royal Dutch Shell Global Asset Management Excellence program will ensure appropriate practices are in place to manage the process safety risk.

During 2006, the business announced Shell Enhance™ froth treatment technology, the first commercial application of a new processing technology that will reduce costs and improve energy efficiency in oil sands production. Developed by Shell Canada with the help of Natural Resources Canada scientists, the new high-temperature process removes sand, fine clay and water from oil sands froth to make clean bitumen suitable for upgrading via hydrogen addition. The initiative is projected to use approximately 10 per cent less water and less energy per barrel of bitumen than conventional low-temperature processing.

The business continues to integrate sustainable development into the life cycle of the operation, from design through reclamation. In 2006, Oil Sands advanced its research into technologies to reduce carbon dioxide (CO_2) emissions from its operations. Also in 2006, the Company began to seek support for a project to sequester carbon. The proposed project has the potential to collect a million tonnes of carbon dioxide from the Company's oil sands operations and transport it via pipeline to oil fields south of Edmonton, Alberta, where it would be used to help recover oil from existing deposits.

The Company also announced its 2006/2007 tree-planting program, with the commitment to plant more than 70,000 trees in Alberta and British Columbia. This program will result in an estimated 43,000 tonnes of CO_2 sequestration.

The AOSP continues to support the communities where it operates, doing business with local and Aboriginal companies in the Regional Municipality of Wood Buffalo. Over 2006, the project employed more than 140 people in various Aboriginal-owned companies in the community of Fort McKay.

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Looking Forward

Oil Sands strives to grow its business through operational excellence and best-in-class operations. Key measures in 2007 toward delivering these objectives include:

- growing in situ production to 40,000 bbls/d by year-end;
- maintaining production from the existing AOSP operations, above the design capacity of 155,000 bbls/d through continued improvements in reliability;
- determining future mining expansion areas by drilling delineation wells on new Shell Canada leases;
- efficiently managing AOSP Expansion 1 project construction through an integrated labour strategy that includes the maximization of modular construction; and
- completing Phase 1 of the 10,000 bbls/d Orion SAGD project.

2007 Capital Investment and Predevelopment Expenditures

Oil Sands' planned investment program for 2007 totals $2,450 million compared with $1,150 million of actual expenditures in 2006. The 2007 program includes $170 million for predevelopment expenses related to future growth projects in Athabasca and Peace River. Planned investments include $220 million for profitability and production optimization projects as well as sustaining capital. Capital spending on growth, primarily the 100,000 bbls/d AOSP Expansion 1 project, will be approximately $1,570 million. The 2007 program also provides capital spending of approximately $490 million for in situ projects.

Risk Management

OIL SANDS TECHNOLOGY

Technology in some key oil sands processes still requires commercial demonstration. Shell Canada addresses this through very focused technology development plans that incorporate a range of activities from detailed technical fundamentals work through to large-scale field demonstration pilot plants. Shell has a number of large technology development groups that are well supported with the facilities and capabilities resident at the Company's Calgary Research Centre.

MINE AND UPGRADER RELIABILITY

Mine and upgrader reliability continues to be a focus area for Oil Sands. In order to achieve best-in-class reliability performance in operations, Shell Canada has begun to implement Royal Dutch Shell's Global Asset Management Excellence (GAME) reliability management program at both AOSP locations. Additional activities include prioritizing capital investments to increase equipment redundancy and continuing to build operations capacity through training and skill development programs.

PROJECT EXECUTION

In addition to labour challenges resulting from a heated market in Alberta, concurrent megaprojects are also constraining AOSP's ability to complete engineering and procure materials. In response to this challenge, Shell Canada has established a rigorous control framework anchored by a strong joint venture and the use of Shell Global Solutions' Integrated Project Management System (iPMS), which contains defined project management processes and structured independent peer reviews.

Oil Products

MANAGEMENT'S DISCUSSION & ANALYSIS

Oil Products 2006 annual earnings were a record $584 million, up significantly from earnings of $434 million for 2005.

Stronger refining margins and a favourable second quarter adjustment of $43 million resulting from changes to federal and Alberta corporate tax rates were partially offset by lower refinery yield. Planned turnarounds at both the Montreal East and Sarnia refineries in 2006, as well as feedstock limitations at both the Scotford and Montreal East refineries, impacted refinery yield. Total Long Term Incentive Plan (LTIP) charges were $13 million in 2006 compared with $56 million in 2005.

Oil Products earnings in the fourth quarter were $22 million compared with $106 million for the same period in 2005. The decrease was mainly due to higher operating expenses, which included an LTIP charge of $36 million, lower refining and marketing margins, and lower refinery yield. The total impact of the planned turnaround at the Sarnia Refinery was $44 million. Refinery yield was also lower in the fourth quarter of 2006 due to feedstock limitations at Montreal East Refinery and lower benzene sales from Scotford.

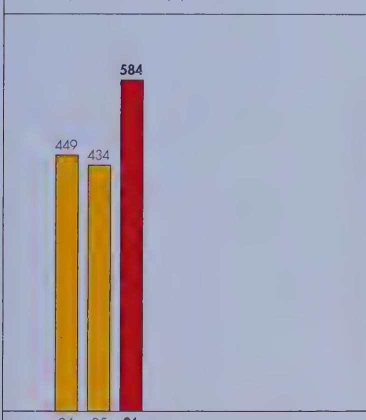
Capital expenditures in 2006 were $402 million compared with $484 million in 2005. The total investment included the completion and commissioning of the ultra low sulphur diesel (ULSD) projects at Shell Canada's Montreal East and Scotford refineries and distribution-related infrastructure. Other key expenditures include the formation of SFJ Inc., comprising the Shell Canada and Flying J road transport businesses in Canada, and capital to maintain the integrity of the manufacturing and distribution supply infrastructure and retail network.

Oil Products Highlights

($ millions except as noted)	**2006**	2005	2004
		(restated)	(restated)
Revenues	**11 367**	10 779	8 535
Earnings	**584**	434	449
Capital employed	**2 599**	2 275	2 129
Capital and predevelopment expenditures	**402**	484	313
Return on average capital employed (%)	**24.0**	19.8	21.2

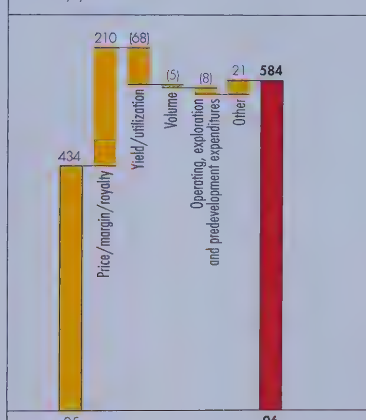
Oil Products Earnings
($ millions)

Record earnings were attributed to stronger refining margins and a tax adjustment partially offset by lower refinery yields.



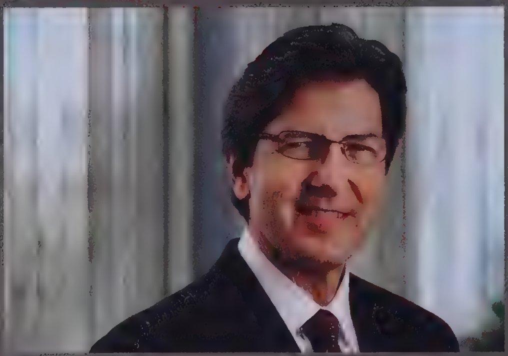
Oil Products Earnings Analysis
($ millions)

Strong refining margins and a favourable tax adjustment were partially offset by lower refinery yield.



Oil Products Unit Costs
(cents per litre)

Shell Canada retained its top ranking within its peer group in spite of increasing unit costs in 2006.



DAVID C. ALDOUS
Senior Vice President, Oil Products

Born in the United States, David Aldous graduated with a BSc in Fuels Engineering from the University of Utah and later received his MBA degree from Northwestern University's Kellogg Graduate School of Management. In 1984, he joined the Shell Chemical Company in Chicago, where he worked in sales and on various commercial assignments. From 1991, he moved through increasingly responsible leadership roles in business management, market development and strategy for Shell's additives, global detergents and olefins businesses. In 2000, David became President and CEO of CRI/Criterion, Inc. and Chairman, Zeolyst International, which are affiliated with the Shell group of companies. David Aldous accepted an assignment with Shell Canada Limited as Senior Vice President, Oil Products, effective October 2006.

In 2006, Oil Products maintained industry leadership in terms of unit costs, unit profitability and return on average capital employed (ROACE). Oil Products ROACE was 24.0 per cent compared with 19.8 per cent the previous year.

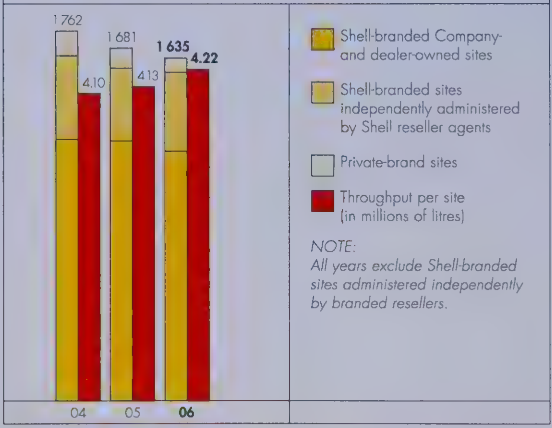
In the fourth quarter, work progressed on designs for a new 150,000 to 250,000 barrel per day heavy oil refinery near Sarnia, Ontario. The team has begun to advance environmental impact assessments and ongoing discussions with various regulatory and community stakeholder groups.

Manufacturing and Supply

In 2006, Shell Canada's refineries produced record light oil volumes by leveraging improvements from capital investments in previous years. The refineries achieved this performance in spite of major planned turnarounds at Sarnia Refinery in the fall and at Montreal East Refinery (MER) in the summer. Unplanned maintenance work at MER in the first and second quarters resulted in reduced throughputs and lower light oil yields.

Retail Site Performance
(number of sites)

Shell Canada continued to optimize its retail site network in 2006 leading to higher throughput per site.



NOTE:
All years exclude Shell-branded sites administered independently by branded resellers.

Construction of the $400-million ULSD projects at the Montreal East and Scotford refineries was completed and commissioned safely, within budget and ahead of new federal regulations that took effect in June. Work on a third party distillate hydrotreater in Sarnia to process distillate from Shell's Sarnia Refinery into ultra low sulphur diesel was also completed in 2006. In addition, a hydrogen plant at Sarnia Refinery was successfully commissioned in the third quarter. This facility supplies hydrogen and steam to Shell as well as hydrogen to a third party for use in the diesel hydrotreating process.

As a result of reduced feedstock and third party hydrogen availability in the year, Scotford Refinery ran at reduced rates on several occasions. Through these periods, supplies to customers were maintained through alternative supply arrangements.

In its 2007 investment plan, the Company announced it would invest $50 million to study the viability of constructing and operating a new refinery near Sarnia, Ontario. This refinery would seek to maximize value from Shell Canada's growing oil sands production in Alberta, while meeting the increasing demand for light oil in Ontario. Preliminary estimates suggest the facility could process between 150,000 and 250,000 bbls/d of heavy crudes. Subject to a satisfactory outcome of predevelopment work, continued favourable business drivers and regulatory approvals, Shell Canada expects to be in a position to make a final investment decision within three years.

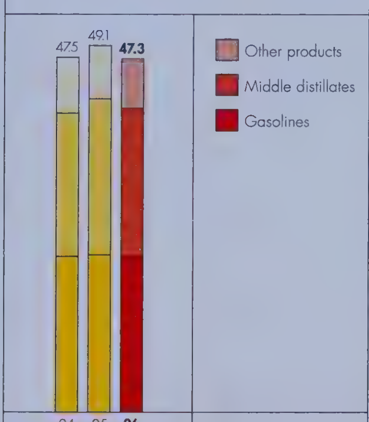
Shell Canada is making required modifications to its facilities to meet Ontario and Saskatchewan regulations requiring ethanol in gasoline. Ethanol-related modifications to the Company's distribution terminals were undertaken in 2006.

Retail

The retail gasoline market remained highly competitive and margins were generally compressed throughout 2006. Price volatility in the Greater Toronto and Greater Vancouver areas put even more pressure on margins in these two large Canadian markets. The price environment also increased pressure on operating costs, in particular variable and pump-price driven costs such as credit card service fees and loyalty awards.

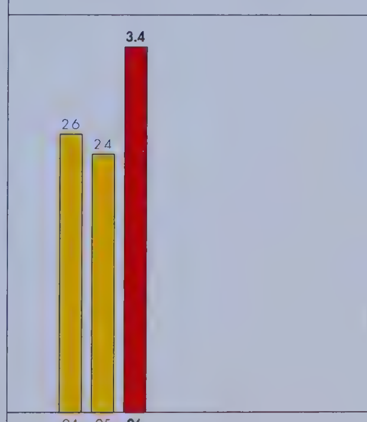
Petroleum Product Sales
(thousands of cubic metres per day)

Product sales were impacted mainly by reductions in the aviation and wholesale sectors.



Earnings Per Litre
(cents per litre)

The improvement is due mainly to improved refining margins in 2006.



Technological advances in 2006 took the shape of improved products across Shell Canada's network. Designation of the Brockville plant as the sole North American supplier of AeroShell aviation lubricants spurred a major debottlenecking program there in 2006. Commissioning of the Company's ULSD project at its Montreal East and Scotford refineries made it possible for ULSD and a new on-road diesel engine oil containing lower levels of phosphorus, sulphur and ash to be distributed to key markets in Canada. The Company also introduced new V-Power™ gasoline, Shell Canada's premium-grade fuel, which was re-engineered to remove additional deposits that normally accumulate in a vehicle's engine.

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In spite of this pressure, both high-volume retailers and traditional competitors increased their presence in the marketplace with new investments and promotional activity in their networks. In 2006, Shell Canada maintained retail market share at an average 17 per cent. A new marketing plan was launched as part of its goal to become one of the world's top fuels retailers. The plan focuses on five key strategies: to become a leader in fuels quality and innovation, to effect efficient payment and loyalty channels, to reflect the competitive price environment for customers, to effectively manage its external channels, and to provide safe, clean and secure retail sites to the Canadian public.

Four global automakers – General Motors, BMW, Honda and Toyota – introduced the TOP TIER Detergent Gasoline standards in 2006. Shell Canada was the first national fuel company to attain the TOP TIER fuel standard by exceeding Canadian General Standards Board requirements around detergency levels in all three grades of Shell gasoline.

CUSTOMER FOCUS

In 2006, the Retail business launched new V-Power™ gasoline, Shell Canada's premium-grade fuel. Originally introduced in 2005, this product was re-engineered to further enhance removal of additional deposits that normally accumulate in a vehicle's engine. The launch was successful, leading to strong premium fuel sales.

Oil Products introduced a new safety program in 2006 to encourage heightened safety and security at its retail sites. Launched through the year at 100 sites in Canada, the program emphasizes reporting of safety incidents as well as communicating the Company's safety standards to retail customers. The business also initiated its new advertising program – *Made to Move*™ – featuring a series of dynamic interpretations of mechanical and human movement.

OPERATIONAL EXCELLENCE

Retail focused in 2006 on the implementation of two other major initiatives to better serve Shell customers. The first is a new point-of-sale system, which will play a crucial role in improving operational effectiveness to enable Retail to deliver consistently high-quality marketing programs and meet the evolving needs of Shell customers. The second is a new automated fuels-pricing system that will allow the business to respond more effectively to increasingly competitive and volatile pricing environments.

NETWORK

Following an extensive review of the Canadian marketplace, the Retail business focused its investment strategy upon Shell-branded retail sites in the Edmonton and Greater Toronto areas. The program included building large new-to-industry retail sites, redeveloping existing sites and closing underperforming ones. During 2006, Shell opened six new Shell-branded retail sites, while completing 15 full-scale redevelopments at existing Shell-branded stations and acquiring two existing retail sites. At year-end, there were 1,635 Shell-branded retail sites compared with 1,681 in 2005. Of the total number, Shell directly operated 732 sites. The average throughput of Shell-operated retail sites increased to 4.22 million litres in 2006 from 4.13 million litres in 2005.

Commercial

The Commercial business sells branded fuel and lubricants to the aviation, agricultural, industrial, transportation and home-heat sectors, and private-label lubricants to a variety of retailers and commercial distributors. The 2006 business environment was challenging as high crude oil and refined product prices compressed margins in most of these commercial sectors. Building on Shell Canada's investment in ULSD, in 2006 the Company's Commercial business launched a new on-road diesel engine oil category: API CJ-4 (offered under the ROTELLA® T and Rimula® brands). The new product is designed to work with ULSD in next-generation diesel engines, and contains lower levels of phosphorus, sulphur and ash than other heavy-duty engine oils.

ROAD TRANSPORT

In 2006, Shell and Flying J Canada Inc. combined their road transport businesses in Canada to form SFJ Inc. The joint venture incorporates a shared $200-million growth plan to build and upgrade existing facilities. It will create a comprehensive network through Shell Canada's truck stops and Flying J's Canadian travel plazas, which offer Shell-branded fuels and highway hospitality services to long-distance truck drivers, recreational vehicle users and local customers. The first of these travel plazas was launched in June 2005 in Sherwood Park, Alberta, with Winnipeg and Saskatoon locations following in 2006, a Calgary travel plaza opening in 2007, and further locations opening across Canada through 2008.

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DIESEL CHANNELS

With plans to proceed with reduced but more significant sales channels to market, Shell sold its home-heating oil businesses in late 2006 to two independent companies: Bluewave Energy Limited Partnership, which owns and operates the business in Ontario and the Maritimes, and Chauffage P. Gosselin Inc., which owns and operates the business in Quebec. This divestment allows Shell Canada to provide customers with access to its branded heating fuel and other products through a lower-cost and more resilient sales channel, maximizing the integrated value of its business. Through 2007, the Company will be completing this sales channel transformation, and establishing simplified and lower-cost support structures.

Distribution and Lubricants Supply

In 2005, Shell Canada Products entered an agreement with Royal Dutch Shell's global aviation business to manufacture aviation piston engine oil and grease at the Brockville and Calgary Lubricants and Grease plants. Following completion of a $4-million upgrade to the Calgary plant in early 2006, Shell Canada became the dominant supplier of AeroShell grease to Royal Dutch Shell's global aviation business. The upgrade is a significant one, as Royal Dutch Shell currently supplies 60 per cent of the global market's aviation greases.

Designation of the Brockville plant as the sole North American supplier of AeroShell aviation lubricants, and expanded production of Pennzoil and Quaker State lubricants for sale in Canada, spurred a major debottlenecking program at that site in 2006. The plant produced 173 million litres in 2006, with growth coming mainly from increases in domestic-branded sales, branded export sales and private-label products manufactured and packaged for third parties. Debottlenecking activities provided additional capacity and enhanced production efficiencies, including construction of new bulk storage tanks and production lines, expansion of railway distribution siding and enhancement of the blending process.

A decommissioning program for the unused aboveground assets of Shell Canada's Shellburn Terminal began in 2005 and continued through 2006. The decommissioning at this facility in north Burnaby, British Columbia, is part of the Company's plan to address redundant storage tanks, piping, buildings and processing units, asbestos abatement and the removal of biological treatment and disposal beds. Shell Canada will spend $4 million to $5 million per year over this five-year course of work.

Health, Safety, Environment and Sustainable Development

Oil Products reported a combined employee and contractor lost-time injury frequency of 0.11 per 200,000 hours worked compared with 0.19 in 2005. The combined total recordable injury frequency was 0.76 per 200,000 hours worked compared with 1.00 in 2005.

Oil Products introduced a process safety scorecard in 2006 that included the American Petroleum Institute definition of process safety and loss of primary containment. The process safety effort in Oil Products is being enhanced with the introduction of the Royal Dutch Shell Global Asset Management Excellence program. This is a major activity across all of our manufacturing sites that will include the Company's distribution terminals and help develop a common understanding around compliance with global standards. Shell Canada will be placing increasing focus on process safety risks in 2007.

The Scotford Refinery was one of 14 facilities recognized in 2006 by Alberta Environment for environmental excellence. The EnviroVista Environmental Leadership Program recognizes facilities with at least five years of exemplary emissions performance, an audited environmental management system, and five years without any prosecutions under Alberta's environmental legislation.

Oil Products met its 2006 targets for reductions in energy use in manufacturing and is on track to meet longer-term greenhouse gas reduction targets. The business's health, safety and environment focus in 2007 will include further improvements in contractor management, enhancement of risk management in downstream operations and continued efforts to improve Oil Products' overall safety culture.

Looking Forward

In 2007, Oil Products' integrated strategy emphasizes the need to:

- maintain the Company's top performer position in Canada as measured by earnings/litre and unit costs;
- determine the viability of a new heavy oil refinery near Sarnia, Ontario;
- target reliable, efficient and safe manufacturing throughput at each of Shell Canada's refineries and lubricant plants;
- improve competitive performance by reducing and enhancing Shell-branded sales channels; and
- deliver on the promise of the Shell brand by offering high-quality, differentiated fuels and lubricants.

2007 Capital Investment and Predevelopment Expenditures

The 2007 investment program for Oil Products totals $470 million, compared to $402 million of actual expenditures in 2006. The program includes capital to maintain the integrity of the manufacturing and distribution supply infrastructure, lubricants manufacturing and marketing networks. As well, there will be continued investment in the Company's road transport business and retail network development, and new investment in the new Sarnia, Ontario refinery project. A significant portion of these expenditures will be used to meet legislative requirements and to cover individual asset integrity investments throughout the supply and distribution infrastructure.

Risk Management

OPERATIONAL RISK

A key driver of competitive performance in the Oil Products business is the reliability of Shell Canada's manufacturing facilities. Comprehensive programs introduced into all these plants focus on rigorous prioritization and systematic application of engineering and maintenance work to promote safe and reliable operations.

BRAND

Shell Canada considers its brand to be the foundation of its profile in Canada. The quality assurance process used to protect the Shell brand mitigates the risks associated with its assets and commodities, including established and emerging fuel products such as ethanol and biodiesel. Oil Products continues to strengthen its focus on consistency of the retail visual image standard and on the effectiveness of product applications and quality assurance across the supply chain.

INTEGRATED STRATEGY RISK

The success of the Company's downstream integrated strategy depends on anticipating the direction our competitors may move in the future and getting out ahead of them competitively. The Company actively monitors competitor activities to ensure the robustness of its own business strategies.

Corporate

MANAGEMENT'S DISCUSSION & ANALYSIS

The Linux computer cluster pictured here with Shell Staff Systems Analyst Neil Rowe represents a technological breakthrough for the Company's Exploration & Production staff. Its massive computing capacity facilitates seismic processing, which allows geophysical staff to visualize underground formations and effectively target reservoirs. Installation of the cluster was completed in 2006.

The Corporate departments are responsible for services that support Shell Canada's three main businesses. These support services include finance, investor relations, information and computing, corporate health, safety, environment and sustainable development, technology (including the Calgary Research Centre), human resources, public affairs, legal services, supply chain management and other corporate services. The activities of these departments are reflected throughout this annual report.

Corporate incurred a loss of $63 million in 2006 compared with earnings of $119 million in 2005. Higher interest charges were offset by lower Long Term Incentive Plan (LTIP) charges in 2006. Previous year earnings included a favourable adjustment of $164 million related to the use of non-capital losses available to the Company resulting from the acquisition of an affiliated company, Coral Resources Canada ULC (Coral) in 2004. Total LTIP charges in 2006 were $12 million compared with $46 million in 2005.

Corporate incurred a loss of $73 million in the fourth quarter of 2006 compared with earnings of $49 million for the corresponding period in 2005. The change was mainly due to higher operating expenses, which included a $35-million LTIP charge, higher interest charges in 2006, and a favourable adjustment of $65 million in 2005 related to the use of non-capital losses available to the Company resulting from the acquisition of Coral.

Financing Activities

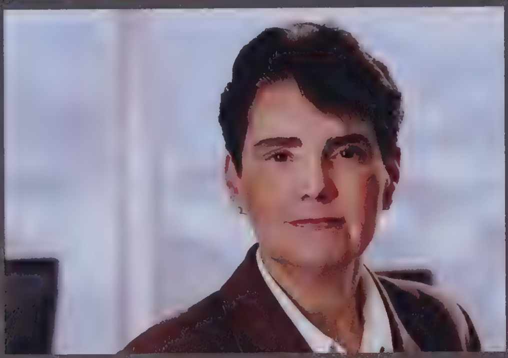
In 2006, cash flow from operations was $2,614 million, down from $3,036 million in 2005. The decrease is largely due to lower bitumen and natural gas liquids volumes, lower natural gas prices and higher expenses. These were partially offset by higher oil prices and refining light oil margins, and a favourable adjustment resulting from changes to federal and Alberta corporate tax rates. Cash flow from operations for the fourth quarter of 2006 was $438 million, down from $926 million for the same period in 2005. The decrease was mainly due to lower natural gas prices, higher LTIP charges and the turnaround at the Sarnia Refinery.

Capital and predevelopment expenditures amounted to $2,426 million for 2006 (excluding the BlackRock Ventures Inc. (BlackRock) purchase price of $2.4 billion net of cash acquired) and $938 million for the fourth quarter, compared with $1,715 million and $709 million, respectively, for 2005. The difference was due to increased investment in growth activities in unconventional oil and gas.

In June 2006, the Company acquired BlackRock. The deal was financed using existing cash on hand of $1.4 billion and a combination of commercial paper and arranged loan facilities.

Contractual Obligations

		Payment Due By Period			
($ millions)	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Short-term borrowings	1 235	1 235	–	–	–
Long-term debt	199	2	149	48	–
Capital lease obligation	1	1	–	–	–
Operating leases	554	80	147	132	195
Purchase obligations	15 915	1 479	1 833	1 564	11 039
Total	**17 904**	**2 797**	**2 129**	**1 744**	**11 234**



CATHY WILLIAMS
Chief Financial Officer

C. L. (Cathy) Williams was born in London, Ontario. She graduated from the University of Western Ontario with a BA and obtained an MBA degree from Queen's University in Kingston, Ontario. In 1984, Cathy began her career with Shell Canada as a Senior Analyst in Corporate Finance. She relocated to London, England in 1989 to become head of Group Central Funds for the Shell International Petroleum Company. Cathy returned to Calgary in 1992 as Manager, Crude Supply and Trading. She was appointed Treasurer in March 1994. In 2001, Cathy moved again to London, England to assume the role of Controller, Shell Europe Oil Products. In April 2003, she was appointed to her present position as Chief Financial Officer, Shell Canada Limited.

Total debt outstanding at the end of 2006 was $1,435 million, which includes $1,036 million of commercial paper issued under the Company's $1.5-billion program, borrowings of $199 million against a $1-billion syndicated facility established in the second quarter of 2006 and $200 million for a mobile equipment lease (covering trucks, scrapers and shovels used at the Muskeg River Mine). This compares with debt on the December 31, 2005 balance sheet of $211 million, mainly due to the mobile equipment lease. The Company also held $1,083 million in cash on the balance sheet on December 31, 2005.

The Company maintained its quarterly dividend at $0.11 per share throughout 2006. Dividends paid in 2006 totalled $363 million compared with $302 million in 2005. Currently, Shell has the highest dividend payout ratio within its peer group of integrated Canadian majors.

All of Shell Canada's financing costs in 2006 were based on floating interest rates. Interest and other financing charges were $42 million compared with $11 million in 2005. Debt increased in 2006 with the acquisition of BlackRock. Starting June 21, 2006, the average cost of debt was 4.40 per cent.

For the first half of 2006, the Company had positive cash balances resulting in interest income of $3 million compared with $9 million in 2005. Shell Canada typically invests cash balances in short-term money market instruments with counterparties that have a strong credit rating.

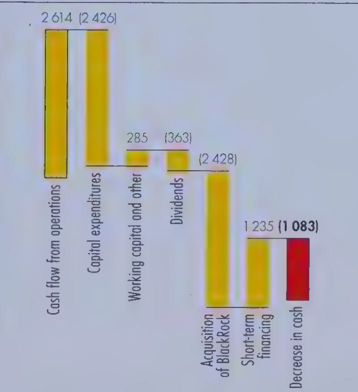
In November 2006, Shell Canada announced a $4.0-billion investment program for 2007. The plan includes $3.6 billion of capital expenditures and $400 million of related exploration and predevelopment expenses. The Company expects to fund this capital program from the existing commercial paper facility, the syndicated credit facility, cash from operations and long-term debt. Shell Canada retains a strong corporate credit rating (AA- with Standard & Poor's Rating Services and AA (low) with Dominion Bond Rating Service). The credit rating allows the Company access to a variety of longer-term capital markets in both Canada and the United States.

Shell Canada has developed a financial plan in concert with the growth-based investment program. This plan will allow the Company to achieve cost-effective borrowing, repayment flexibility and the optimal capital structure for the Company. Shell Canada's strong balance sheet and market borrowing capacity allow for a wide variety of potential debt instruments, which include commercial paper, medium/long-term markets (domestic and foreign), additional bank loans and accounts receivable securitization. The Company will use a variety of debt instruments to structure the debt portfolio to ensure repayment terms are matched with the capital spending profile and cash generation of the Company.

It is planned that the Company will use growing operational cash flows and capital spending discipline to maintain a strong investment-grade debt rating throughout the growth plan.

Cash Flow and Financing
($ millions)

The BlackRock acquisition and increasing investment in unconventional oil and gas led to a decrease in cash.



Outstanding Shares

As of February 28, 2007, the Company had 825,831,826 common shares outstanding. The 100 outstanding preference shares were redeemed in 2006. There were 20,917,878 employee stock options (stock appreciation rights) outstanding as of February 28, 2007 and of that total 13,885,020 are exercisable.

On January 23, 2007, Royal Dutch Shell plc (through its affiliate, Shell Investments Limited) confirmed its intention to make an offer to acquire the minority shares of Shell Canada for cash consideration of $45 per common share. The offer is open for acceptance until 8:00 p.m. (Toronto time) on March 16, 2007, unless it is withdrawn or extended.

Pension Plan

Shell Canada bases its pension calculation on long-term rates of return. In 2006, Shell Canada's long-term rate of return assumption was seven per cent, reflecting the market performance expectation of plan assets. In 2006, Shell Canada made current service cost and solvency contributions totalling $109 million to its defined benefit plan.

Accounting Standards

CANADIAN

Shell Canada retroactively adopted Emerging Issues Committee (EIC-162) Abstract 162 *Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date,* effective December 31, 2006. This standard requires that companies expense stock options related to individuals eligible to retire at or during the vesting period of the stock option. The impact on Shell Canada's financial statements is discussed in Note 1 to the Consolidated Financial Statements.

FINANCIAL INSTRUMENTS/HEDGES/ COMPREHENSIVE INCOME

Shell Canada will adopt the Canadian Institute of Chartered Accountants (CICA) standards 3855 *Financial Instruments – Recognition and Measurement*, 3865 *Hedges* and 1530 *Comprehensive Income* for the reporting year 2007, as they are effective for years beginning on or after October 1, 2006. It is not anticipated that the adoption of these policies will have a material impact on the Company.

INVENTORY

The Accounting Standards Board has issued an Exposure Draft of new Section 3031, *Inventories*, to replace existing Section 3030, *Inventories*. The proposed effective date is for interim and annual financial statements relating to fiscal years beginning on or after July 1, 2007. The last-in, first-out basis of cost determination currently applied by Shell Canada to its inventories will no longer be acceptable under the new section. The proposed standard would result in a material increase in inventory.

UNITED STATES

Financial Accounting Standards Board (FASB) Interpretations (FIN) 48, *Accounting for Uncertainty in Income Taxes* – An interpretation of FASB 109. This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken, or expected to be taken, in a tax return. The effective date is for fiscal years beginning after December 15, 2006. The adoption is prospective. The proposed guidance would not result in a material change in tax positions.

Critical Accounting Estimates

In the compilation of the financial statements, some estimates reflect management's best judgments. These estimates are based on historical experience and other factors that management deems appropriate. The Audit Committee of the Board of Directors reviews annually any significant changes in estimates. The following summary outlines the critical accounting estimates made by Shell Canada management and should be read in conjunction with the section "Accounting Policies" on pages 57 to 59 of the Notes to Consolidated Financial Statements.

HYDROCARBON RESERVES

Reserves quantities are estimated in accordance with established guidelines of the Canadian securities regulators, United States Financial Accounting Standards Board and United States Securities Exchange Commission for conventional oil and gas and minable bitumen reserves. Determination of reserves within these guidelines is based on established geological and engineering principles and involves interpretation of geological data. Estimates are subject to revision as additional exploration and development data is collected and new information regarding producing operations and technology becomes available. Revisions could also occur as economic and operating conditions change, or as properties are divested or acquired. Although there is a reasonable certainty of recovering proved reserves, they are based on estimates that are subject to some variability. Revisions to reserves estimates will affect the depreciation and depletion on Exploration & Production and Oil Sands assets that are calculated on the unit-of-production basis.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations and other environmental liabilities are based on commercial engineering estimated costs and historical experience. Calculations take into account the anticipated method and extent of remediation consistent with legal requirements, current technology and the possible use of the location. Since these estimates are specific to the locations involved, there are many individual assumptions underlying the Company's total asset retirement obligations and provision for other environmental liabilities. Significant changes to the assumptions behind these estimates and the timing may result in material changes to the obligation.

Asset retirement obligations are discounted using a credit-adjusted risk-free rate. Payments to settle these obligations occur on an ongoing basis and will continue over the life of the operating assets, which can exceed 25 years. The discount rate on incremental asset retirement obligation estimates will be adjusted as appropriate to reflect long-term changes in market rates and outlook.

EMPLOYEE FUTURE BENEFITS

An independent actuary determines Shell Canada's costs of pension and other retirement benefits using the projected benefit method. The calculation takes into account length of service and estimates of expected plan investment performance, salary increases, expected health care costs and the discount rate for the benefit obligation. Senior management reviews key pension assumptions annually and third party actuaries review them at least every three years.

The assumed long-term rate of return used in 2006 was seven per cent (2005 – 7.25 per cent) compared to an average of actual returns on the defined benefit pension trust portfolio of 8.8 per cent annually over the last 10 years ended December 31, 2006. Shell Canada's exposure to changes in the underlying assumptions is summarized in Note 9 to the Consolidated Financial Statements. The obligation and expense could increase or decrease if there were to be a change in these estimates. Pension expenses represented less than one per cent of Shell Canada's total expenses in 2006.

IMPAIRMENT OF ASSETS

Assets that have an indefinite useful life and are not subject to amortization are tested annually for impairment. Assets, which are subject to amortization, are reviewed for impairment when events or a change in circumstances indicate that the carrying amount may not be recoverable. An impairment loss would be recognized for the amount by which the asset's carrying amount exceeds its amount recoverable.

For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows that are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Estimates of future cash flows are based on management's estimates of future prices, market supply and demand, product margins, and, in the case of oil and gas properties, the expected future production volumes.

Related Party Transactions

In the course of regular business activities, Shell Canada enters into transactions with related parties, including affiliates of Royal Dutch Shell plc. The products sold to affiliates include natural gas, petroleum products, chemicals and services. The main product purchased from affiliates is crude oil. Product purchases and sales are at commercial rates. Service fees, which represent approximately one per cent of the total related party transactions, are at cost.

On January 23, 2007, the Company entered into a support agreement with Shell Investments Limited (the "Offeror"), in connection with the offer by Royal Dutch Shell plc to acquire the minority shares of Shell Canada for cash consideration of $45 per common share. The support agreement sets forth, among other things, the terms and conditions upon which the offer is to be made by the Offeror. This includes customary representations and warranties and covenants on the part of Shell Canada and the Offeror, including covenants of Shell Canada (i) to carry on business in the ordinary course, (ii) not to issue securities or make changes to its capital structure, (iii) to assist the Offeror in completion of the offer, (iv) not to interfere with or delay the completion of the offer, (v) to allow the Offeror access to the books, records, management and properties of Shell Canada, and (vi) not to frustrate the Offeror's attempt to designate all of the Directors of the Board of Directors provided that the Offeror takes up and pays for common shares pursuant to the offer and that the Minimum Condition (as defined in the support agreement) shall have been satisfied (and not waived). The full text of the support agreement and related offer documents can be found under Shell Canada's profile at **www.sedar.com**.

Technology

Technology experts provide technical and engineering support to secure the best possible performance from Shell Canada's assets and new business opportunities. Access to Royal Dutch Shell's worldwide research and technical support capabilities augments Shell Canada's capabilities.

Shell regularly assesses asset integrity by reviewing management systems and conducting health, safety and environmental and integrity assurance audits of the Company's various facilities.

Risk Management

FINANCIAL RISKS

Currency risk increases when foreign currency rates fluctuate compared with the Canadian dollar. The risk grows in proportion to the volume of activity involving foreign currency. Shell Canada regularly executes commodity transactions priced in other currencies, mainly U.S. dollars. The majority of these U.S. dollar transactions involve crude oil purchases. Netting foreign cash flows across the various businesses each month helps reduce the effect of these fluctuations for the Company overall. Shell Canada reviews all foreign currency commitments on major capital projects and, depending on specific circumstances, may hedge on a transaction-by-transaction basis. At year-end 2006, no material hedges were in place.

Interest rate fluctuations affect Shell Canada's total interest expense. The strength of the Company's balance sheet allowed it to continue with 100 per cent floating rate interest exposure in 2006 and take advantage of lower interest rates.

To reduce the financial risk resulting from potential incidents, the Company purchases appropriate insurance against risks associated with all its operations and projects. Shell Canada's major insurance programs consist of executive protection, property damage and business interruption, third party liability and construction insurance. The Company has also put in place property and delay-in-startup construction insurance coverage for the Athabasca Oil Sands Project Expansion 1.

Financial Information

Year Ended December 31, 2006

Management's Report

TO THE SHAREHOLDERS OF SHELL CANADA LIMITED

Consolidated Financial Statements

The management of Shell Canada Limited is responsible for the preparation of all information included in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and necessarily include amounts based on management's informed judgments and estimates. Financial information included elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfils its financial reporting responsibilities. The Audit Committee is composed of independent directors who are not employees of the Corporation. The committee reviews the financial content of the Annual Report and meets regularly with management, internal audit and PricewaterhouseCoopers LLP to discuss internal controls, accounting, auditing and financial reporting matters. The committee recommends the appointment of the external auditors to shareholders. The committee reports its findings to the Board of Directors for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Management's Report on Internal Control over Financial Reporting

Management, including the Company's Chief Executive Officer and Chief Financial Officer, is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Management has conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Shell Canada's internal control over financial reporting was effective as of December 31, 2006.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves diligence and compliance, and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design safeguards into the process to reduce, though not eliminate, this risk.

PricewaterhouseCoopers LLP, independent auditors, have audited (1) management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 and (2) the effectiveness of our internal control over financial reporting as of December 31, 2006, as stated in their report herein.

Clive Mather

C. Williams

Clive Mather
President and Chief Executive Officer

March 8, 2007

Cathy L. Williams
Chief Financial Officer

Independent Auditors' Report

TO THE SHAREHOLDERS OF SHELL CANADA LIMITED

We have completed an integrated audit of the consolidated financial statements and internal control over financial reporting of Shell Canada Limited as of December 31, 2006 and audits of its December 31, 2005 and December 31, 2004 consolidated financial statements. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Shell Canada Limited as at December 31, 2006, 2005 and 2004, and the related consolidated statements of earnings and retained earnings and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit of the Company's financial statements as at December 31, 2006 and for the year then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audits of the Company's financial statements as at December 31, 2005 and December 31, 2004 and for each of the two years in the period ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2006, 2005 and 2004 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

Internal Control over Financial Reporting

We have also audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as at December 31, 2006 is fairly stated, in all material respects, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

March 8, 2007

Consolidated Statement of Earnings and Retained Earnings

Year ended December 31 ($ millions)	2006	2005	2004
		(restated)	(restated)
REVENUES			
Sales and other operating revenues	**14 651**	14 171	11 232
Dividends, interest and other income	**155**	223	53
Total revenues	**14 806**	14 394	11 285
EXPENSES			
Cost of goods sold	**8 627**	7 900	6 068
Operating, selling and general	**2 494**	2 419	2 053
Transportation	**306**	331	309
Exploration	**131**	120	185
Predevelopment	**149**	64	45
Depreciation, depletion, amortization and retirements	**822**	782	722
Interest on long-term debt	**10**	8	16
Other interest and financing charges	**32**	3	7
Total expenses	**12 571**	11 627	9 405
EARNINGS			
Earnings before income tax	**2 235**	2 767	1 880
Current income tax	**518**	602	617
Future income tax	**(21)**	164	(20)
Total income tax (Note 4)	**497**	766	597
Earnings	**1 738**	2 001	1 283
Per common share (dollars) (Note 12)			
Earnings – basic	**2.11**	2.43	1.55
Earnings – diluted	**2.09**	2.40	1.54
RETAINED EARNINGS			
Balance at beginning of year	**7 675**	6 009	5 046
Earnings	**1 738**	2 001	1 283
	9 413	8 010	6 329
Common shares buy-back (Note 3)	**–**	33	61
Dividends	**363**	302	259
Balance at end of year	**9 050**	7 675	6 009

Consolidated Statement of Cash Flows

Year ended December 31 ($ millions)	2006	2005 (restated)	2004 (restated)
CASH FROM OPERATING ACTIVITIES			
Earnings	**1 738**	2 001	1 283
Exploration and predevelopment	**111**	99	160
Non-cash items			
Depreciation, depletion, amortization and retirements	**822**	782	722
Future income tax	**(21)**	164	(20)
Other items	**(36)**	(10)	(20)
Cash flow from operations	**2 614**	3 036	2 125
Movement in working capital and operating activities			
Accounts receivable securitization program	**–**	(150)	(431)
Other working capital and operating items	**(117)**	175	421
	2 497	3 061	2 115
CASH INVESTED			
Capital and predevelopment expenditures	**(2 426)**	(1 715)	(951)
Acquisition of BlackRock Ventures Inc. (Note 13)	**(2 428)**	–	–
Movement in working capital from investing activities	**309**	69	(7)
Capital expenditures and movement in working capital	**(4 545)**	(1 646)	(958)
Proceeds on disposal of properties, plant and equipment	**106**	6	4
Investments and other	**(19)**	–	–
	(4 458)	(1 640)	(954)
CASH FROM FINANCING ACTIVITIES			
Common shares buy-back (Note 3)	**–**	(34)	(63)
Proceeds from exercise of common share stock options	**7**	6	37
Redemption of preference shares (Note 3)	**(1)**	–	–
Dividends paid	**(363)**	(302)	(259)
Long-term debt and other	**–**	(135)	(600)
Short-term financing	**1 235**	–	(149)
	878	(465)	(1 034)
(Decrease)/Increase in cash	**(1 083)**	956	127
Cash at beginning of year	**1 083**	127	–
Cash at end of year [1]	**–**	1 083	127
Supplemental disclosure of cash flow information			
Dividends received	**13**	15	14
Interest received	**57**	42	28
Interest paid	**42**	12	28
Income tax paid	**743**	683	303

[1] Cash comprises cash and highly liquid short-term investments.

Consolidated Balance Sheet

As at December 31 ($ millions)	**2006**	2005 (restated)	2004 (restated)
ASSETS			
Current assets			
Cash and short-term investments	**–**	1 083	127
Accounts receivable	**1 940**	1 821	1 213
Inventories			
Crude oil, products and merchandise	**523**	535	501
Materials and supplies	**100**	92	83
Prepaid expenses	**50**	71	85
Future income tax (Note 4)	**299**	327	316
	2 912	3 929	2 325
Investments, long-term receivables and other	**741**	671	549
Properties, plant and equipment (Note 2)	**13 669**	9 066	8 034
Goodwill	**234**	–	–
Total assets	**17 556**	13 666	10 908
LIABILITIES			
Current liabilities			
Short-term borrowings (Note 6)	**1 235**	–	–
Accounts payable, accrued liabilities and other	**2 752**	2 272	1 687
Income and other taxes payable	**535**	687	657
Current portion of asset retirement and other long-term obligations	**101**	26	35
Current portion of long-term debt (Note 6)	**3**	11	136
	4 626	2 996	2 515
Asset retirement and other long-term obligations (Note 7)	**611**	538	417
Long-term debt (Note 6)	**197**	200	1
Future income tax (Note 4)	**2 542**	1 733	1 448
Total liabilities	**7 976**	5 467	4 381
Commitments and contingencies (Note 11)			
SHAREHOLDERS' EQUITY			
Capital stock (Note 3)			
100 4% preference shares	**–**	1	1
825 662 514 common shares (2005 – 825 102 612; 2004 – 825 727 686)	**530**	523	517
	530	524	518
Retained earnings	**9 050**	7 675	6 009
Total shareholders' equity	**9 580**	8 199	6 527
Total liabilities and shareholders' equity	**17 556**	13 666	10 908

The consolidated financial statements have been approved by the Board of Directors.

Clive Mather
Director

Kerry L. Hawkins
Director

Notes to Consolidated Financial Statements

Shell Canada's consolidated financial statements are prepared in accordance with accounting principles generally accepted in Canada. The Corporation's major accounting policies are summarized as follows:

Note 1. Accounting Policies

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Shell Canada Limited and its subsidiary companies. The financial statements reflect the Corporation's proportionate interests in joint ventures.

INVENTORIES

The cost of crude oil, products and merchandise are stated at the lower of cost, applied on the last-in, first-out (LIFO) basis, or net realizable value. All other inventories are stated at the lower of cost, applied on a weighted average basis, or net realizable value.

INVESTMENTS

Investments in companies over which Shell Canada exercises significant influence are accounted for using the equity method. Accordingly, the book value of the investment in such companies equals the cost of the investment, plus Shell Canada's share of earnings since the investment date, less dividends received. Other long-term investments are recorded at cost. Short-term investments are carried at the lower of cost or market value and are highly liquid securities with a maturity of three months or less when purchased.

EXPLORATION AND DEVELOPMENT COSTS

The Corporation follows the successful efforts method of accounting for oil and gas exploration and development activities. Under this method, acquisition costs of properties are capitalized. Exploratory drilling costs are initially capitalized and costs relating to wells subsequently determined to be unsuccessful are charged to earnings. Exploratory drilling costs related to exploratory wells in an area that requires major capital expenditures are carried as an asset, provided that i) there have been sufficient oil and gas reserves found to justify completion as a producing well if the required capital expenditure is made, and ii) drilling of additional exploratory wells is underway or firmly planned for the near future. Other exploration costs are charged to earnings. For mining activities, property acquisition and development costs are capitalized.

DEPRECIATION, DEPLETION AND AMORTIZATION

Depreciation and depletion on oil and gas and mining assets are provided on the unit-of-production basis. Land and lease costs relating to producing properties and costs of gas plants are depleted and depreciated over remaining proved reserves. Oil and gas and mine development costs are depleted and depreciated over remaining proved developed reserves. The mine extraction plant and other facilities are depreciated over remaining proved and probable reserves. Amortization of unproved oil and gas properties is based on the estimated life of the asset and past experience. Costs relating to refinery, upgrader, mine equipment, mine and upgrader preproduction, distribution, marketing and non-resource assets are depreciated on the straight-line basis over each asset's estimated useful life. Costs related to turnaround activities are expensed as incurred.

ASSET RETIREMENT OBLIGATIONS

Legal obligations associated with site restoration on the retirement of assets with determinable useful lives are recognized when they are incurred, which is typically at the time the assets are installed. The obligations are initially measured at fair value and discounted to present value. A corresponding amount equal to that of the initial obligation is added to the capitalized costs of the related asset. Over time, the discounted asset retirement obligation amount will be accreted for the change in its present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets.

Asset retirement obligations and other environmental liabilities are based on commercial engineering estimated costs and historical experience, taking into account the anticipated method and extent of remediation consistent with legal requirements and current technology.

Note 1. Accounting Policies (continued)

REVENUES

Revenues are recognized upon delivery. Inter-segment sales, which are accounted for at estimated market-related values, are included in revenues of the segment making the transfer. On consolidation, such inter-segment sales and any associated estimated profits in inventory are eliminated.

ROYALTIES AND MINERAL TAXES

All royalty entitlements and mineral taxes are reflected as reductions in sales and other operating revenues.

EMPLOYEE FUTURE BENEFITS

The costs of the defined benefit pension plan and other retirement benefits are actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are valued at a market-related value. The excess of the net actuarial gain or loss over 10 per cent of the greater of the benefit obligation and the market-related value of plan assets is amortized over the expected average remaining service period of active employees. The cost of the Company's portion of the defined contribution pension plan is expensed as incurred.

FOREIGN CURRENCY TRANSLATION

Monetary items are translated to Canadian dollars at rates of exchange in effect at the end of the period. The gains and losses on the translation of foreign denominated monetary items are recognized in earnings.

DERIVATIVE INSTRUMENTS

The Company uses derivative instruments in the management of its foreign currency, interest rate and commodity price exposures. The Company does not use derivative instruments for speculative purposes.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting, whereby derivative instruments are recorded on the Company's balance sheet as either an asset or liability with changes in fair value recorded to earnings.

Foreign exchange contracts are used to hedge certain foreign purchases and sales. Those foreign exchange contracts are revalued at the exchange rate in effect at the end of each reporting period. Foreign exchange gains and losses are recognized in earnings.

Interest rate swaps are mark-to-market and used to manage interest rate exposure. Differentials under interest rate swap arrangements are recognized by adjustments to interest expense.

Energy futures are used to reduce exposure to price fluctuations in some contractual energy purchases and sales. Those energy futures are mark-to-market at the end of each reporting period and with the changes recognized in earnings.

MEASUREMENT UNCERTAINTY

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates used in the preparation of these financial statements include the estimate of proved and probable reserves, asset retirement obligations, impairment of assets, and employee future benefits.

STOCK-BASED COMPENSATION PLANS

The Corporation has stock-based compensation plans, which are described in Note 3. For options under the Long Term Incentive Plan (LTIP) that have share appreciation rights attached to them, a liability for expected cash settlements is accrued over the vesting period of the options based on the difference between the exercise price of the options and the market price of the Company's common shares. The liability is revalued at the end of each reporting period to reflect changes in the market price of the Company's common shares and the net change is recognized in earnings. When options are surrendered for cash, the cash settlement reduces the outstanding liability. When options are exercised for common shares, consideration paid by the option holders and the previously recognized liability associated with the option are recorded as share capital.

For options that do not have share appreciation rights (SARs) attached to them, stock-based compensation is accounted for using the Black-Scholes valuation method. The Company records compensation expense over the vesting period for stock options granted to employees, with the exception of employees eligible to retire. In the latter case, the options are expensed at the earliest eligible retirement date. Any consideration paid by employees on exercise of stock options or purchase of stock is credited to share capital.

MINE STRIPPING COSTS

Mine stripping costs are expensed in the same period they are incurred.

INCOME TAXES

The Corporation uses the liability method to account for income taxes. Under the liability method, future income taxes are based on the differences between assets and liabilities reported for financial accounting purposes from those reported for income tax. Future income tax assets and liabilities are measured using substantively enacted tax rates. The impact of a change in tax rates is recognized in the current period income.

GOODWILL

Goodwill is tested for impairment on an annual basis. If indications of impairment are present, a loss would be charged to earnings for the amount that the carrying value of goodwill exceeds its fair value. Goodwill has been allocated to business units within the Company's segments.

CHANGE IN ACCOUNTING POLICY

Stock-Based Compensation For Employees Eligible To Retire Before The Vesting Date

Shell Canada adopted Emerging Issues Committee (EIC) Abstract 162 *Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date* with prior period restatement as required. The EIC mandates that employees who are eligible to retire at the grant date, or will become eligible to retire during the vesting period, should have their stock-based compensation awards recognized at the earliest eligible retirement date.

The impact of this change resulted in a reduction to the LTIP expense of $10 million for the year ended December 31, 2006 (2005 – $13 million increase in expense; 2004 – $3 million increase in expense). Earnings per common share are increased by 0.01 for the period ended December 31, 2006 (2005 – 0.01 decrease; 2004 – 0.01 decrease). On a diluted basis, earnings per common share are increased by 0.02 for the period ended December 31, 2006 (2005 – 0.01 decrease; 2004 – 0.01 decrease).

RECLASSIFICATION

Certain other information provided for prior years has been reclassified to conform to the current presentation.

Note 2. Segmented Information

The operating segments are those adopted by senior management of the Corporation to determine resource allocations and assess performance. In all material respects, the segmented information is applied consistently in accordance with the Corporation's significant accounting policies. The Corporation's revenues are attributed principally to Canada where all of its major properties, plants and equipment are located.

Effective January 1, 2006, the Peace River business was transferred from Exploration & Production (E&P) to the Oil Sands business unit. Segmented information for the relevant business units has been reclassified for the prior periods.

Segmented financial results and properties, plant and equipment data are reported as if the segments were separate entities.

EARNINGS ($ millions)

TOTAL			
2006	2005 (restated)	2004 (restated)	
1 325	1 577	1 306	Natural gas
713	773	700	Natural gas liquids
1 792	1 559	1 040	Crude oil and bitumen
(402)	(485)	(364)	Royalties
4 731	4 361	3 615	Gasolines
4 537	4 432	3 047	Middle distillates
1 653	1 675	1 600	Other products
457	502	341	Other revenues
–	–	–	Inter-segment sales
14 806	14 394	11 285	**Total revenues**
8 627	7 900	6 068	Cost of goods sold
–	–	–	Inter-segment purchases
2 494	2 419	2 053	Operating, selling and general
306	331	309	Transportation
131	120	185	Exploration
149	64	45	Predevelopment
822	782	722	Depreciation, depletion, amortization and retirements
10	8	16	Interest on long-term debt
32	3	7	Other interest and financing charges
12 571	11 627	9 405	**Total expenses**
2 235	2 767	1 880	Earnings (loss) before income tax
518	602	617	Current income tax
(21)	164	(20)	Future income tax
497	766	597	Total income tax
1 738	2 001	1 283	**Earnings (loss)**

The Corporation has the following segments:

Exploration & Production includes exploration, production and marketing activities for natural gas, natural gas liquids and sulphur.

Oil Sands includes mining and extraction of bitumen, upgrading of mined bitumen to synthetic crude oils, in situ bitumen and marketing of these products.

Oil Products includes the manufacturing, distribution and selling of the Corporation's refined petroleum products.

Corporate includes controllership, financing activities, administration and general corporate facility management.

EXPLORATION & PRODUCTION			OIL SANDS			OIL PRODUCTS			CORPORATE		
2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
	(restated)	(restated)		(restated)	(restated)		(restated)	(restated)		(restated)	(restated)
1 325	1 577	1 306	**–**	–	–	**–**	–	–	**–**	–	–
713	773	700	**–**	–	–	**–**	–	–	**–**	–	–
–	–	–	**1 792**	1 559	1 040	**–**	–	–	**–**	–	–
(381)	(470)	(354)	**(21)**	(15)	(10)	**–**	–	–	**–**	–	–
–	–	–	**–**	–	–	**4 731**	4 361	3 615	**–**	–	–
–	–	–	**–**	–	–	**4 537**	4 432	3 047	**–**	–	–
274	327	329	**–**	–	–	**1 379**	1 348	1 271	**–**	–	–
53	72	41	**68**	141	32	**258**	226	216	**78**	63	52
216	275	111	**1 524**	1 671	1 102	**462**	412	386	**–**	–	–
2 200	2 554	2 133	**3 363**	3 356	2 164	**11 367**	10 779	8 535	**78**	63	52
–	–	–	**1 024**	790	544	**7 599**	7 108	5 525	**4**	2	(1)
221	241	151	**417**	416	318	**1 564**	1 701	1 130	**–**	–	–
446	467	375	**792**	692	591	**1 153**	1 139	1 031	**103**	121	56
306	331	309	**–**	–	–	**–**	–	–	**–**	–	–
131	120	185	**–**	–	–	**–**	–	–	**–**	–	–
36	38	45	**92**	26	–	**21**	–	–	**–**	–	–
378	348	344	**211**	228	184	**229**	204	193	**4**	2	1
–	–	–	**–**	–	–	**–**	–	–	**10**	8	16
–	–	–	**–**	–	–	**–**	–	–	**32**	3	7
1 518	1 545	1 409	**2 536**	2 152	1 637	**10 566**	10 152	7 879	**153**	136	79
682	1 009	724	**827**	1 204	527	**801**	627	656	**(75)**	(73)	(27)
153	411	385	**195**	41	16	**190**	296	249	**(20)**	(146)	(33)
30	(67)	(111)	**(86)**	380	135	**27**	(103)	(42)	**8**	(46)	(2)
183	344	274	**109**	421	151	**217**	193	207	**(12)**	(192)	(35)
499	665	450	**718**	783	376	**584**	434	449	**(63)**	119	8

Note 2. Segmented Information (continued)

CASH FLOW ($ millions)

TOTAL 2006	2005 (restated)	2004 (restated)	
2 614	3 036	2 125	Cash flow from operations
(117)	25	(10)	Movement in working capital and operating activities
2 497	3 061	2 115	**Cash from operating activities**
(2 426)	(1 715)	(951)	Capital and predevelopment expenditures
(2 428)	–	–	Acquisition of BlackRock Ventures Inc.
309	69	(7)	Movement in working capital from investing activities
(4 545)	(1 646)	(958)	
87	6	4	Other cash invested
878	(465)	(1 034)	Cash from financing activities
(1 083)	956	127	**(Decrease)/increase in cash**

CAPITAL EMPLOYED ($ millions)

TOTAL 2006	2005 (restated)	2004 (restated)	
2 912	3 929	2 325	Current assets
741	671	549	Investments, long-term receivables and other
3 653	4 600	2 874	
20 809	15 575	13 843	Properties, plant and equipment at cost[1]
(7 140)	(6 509)	(5 809)	Accumulated depreciation, depletion and amortization
13 669	9 066	8 034	Net properties, plant and equipment
234	–	–	Goodwill
17 556	13 666	10 908	Total assets
(6 541)	(5 256)	(4 244)	Total liabilities less long-term debt and short-term borrowings
11 015	8 410	6 664	**Capital employed**

[1] Property, plant and equipment include assets under construction totalling: $1,888 million in 2006 (2005 – $988 million; 2004 – $606 million).

EXPLORATION & PRODUCTION			OIL SANDS			OIL PRODUCTS			CORPORATE		
2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
	(restated)	(restated)		(restated)	(restated)		(restated)	(restated)		(restated)	(restated)
990	1 024	844	**843**	1 411	696	**831**	527	578	**(50)**	74	7
(167)	(68)	161	**(135)**	17	129	**(187)**	241	148	**372**	(165)	(448)
823	956	1 005	**708**	1 428	825	**644**	768	726	**322**	(91)	(441)
(828)	(796)	(435)	**(1 150)**	(420)	(195)	**(402)**	(484)	(313)	**(46)**	(15)	(8)
–	–	–	**(2 428)**	–	–	**–**	–	–	**–**	–	–
84	23	7	**217**	43	(24)	**6**	1	11	**2**	2	(1)
(744)	(773)	(428)	**(3 361)**	(377)	(219)	**(396)**	(483)	(302)	**(44)**	(13)	(9)
–	1	1	**68**	4	–	**12**	1	2	**7**	–	1
–	–	–	**–**	–	–	**–**	–	–	**878**	(465)	(1 034)
79	184	578	**(2 585)**	1 055	606	**260**	286	426	**1 163**	(569)	(1 483)

EXPLORATION & PRODUCTION			OIL SANDS			OIL PRODUCTS			CORPORATE		
2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
	(restated)	(restated)		(restated)	(restated)		(restated)	(restated)		(restated)	(restated)
586	701	514	**536**	172	227	**1 650**	1 745	1 472	**140**	1 311	112
155	116	100	**131**	89	69	**428**	378	304	**27**	88	76
741	817	614	**667**	261	296	**2 078**	2 123	1 776	**167**	1 399	188
6 249	5 510	4 792	**8 879**	4 735	4 139	**5 534**	5 215	4 802	**147**	115	110
(3 405)	(3 066)	(2 595)	**(894)**	(722)	(606)	**(2 766)**	(2 650)	(2 536)	**(75)**	(71)	(72)
2 844	2 444	2 197	**7 985**	4 013	3 533	**2 768**	2 565	2 266	**72**	44	38
–	–	–	**234**	–	–	**–**	–	–	**–**	–	–
3 585	3 261	2 811	**8 886**	4 274	3 829	**4 846**	4 688	4 042	**239**	1 443	226
(1 293)	(1 377)	(1 261)	**(2 904)**	(1 594)	(997)	**(2 247)**	(2 413)	(1 913)	**(97)**	128	(73)
2 292	1 884	1 550	**5 982**	2 680	2 832	**2 599**	2 275	2 129	**142**	1 571	153

Note 3. Capital Stock and Stock-Based Compensation

CAPITAL STOCK

Shell Canada Limited carries on business under the *Canada Business Corporations Act*. Common shares are without nominal or par value and are authorized in unlimited number.

Effective September 30, 2006, the Corporation redeemed the previously outstanding 100 preference shares for cash consideration in accordance with their terms.

The Company, through a series of normal course issuer bids, has repurchased common shares totalling: 2006 – nil (2005 – 1,205,841; 2004 – 2,822,700) at a cost of nil in 2006 (2005 – $34 million; 2004 – $63 million).

COMMON SHARES	2006		2005		2004	
	Shares	($ millions)	Shares	($ millions)	Shares	($ millions)
Balance at beginning of year	**825 102 612**	**523**	825 727 686	517	825 126 477	480
Activity during year						
Options exercised	**559 902**	**7**	580 767	7	3 423 909	39
Normal course issuer bid	**–**	**–**	(1 205 841)	(1)	(2 822 700)	(2)
Balance at year-end	**825 662 514**	**530**	825 102 612	523	825 727 686	517

STOCK-BASED COMPENSATION

Under the LTIP, the Company may grant options to executives, senior management and other employees. The exercise price of each option equals the market price of the Company's stock on the date of grant and the maximum term of an option is 10 years. Options may not be exercised during the one-year period following the date of grant, after which time one-third of the options may be exercised in each of the next three years on a cumulative basis. For executives and senior management, 50 per cent of the options are "performance-based" and their award is tied to the Company's Total Shareholder Return (TSR). For the performance-based options to vest, the Company's three-year TSR must exceed the average of the Corporation's comparator group at the end of the three-year period after being granted. If the Corporation's TSR does not meet the target, the Management Resources and Compensation Committee may determine, in its sole discretion, that all or a portion of the options granted shall vest. If these options vest, they must be exercised within seven years of the date of vesting.

In 2006, the Company granted 4,382,800 (2005 – 5,926,050; 2004 – 5,089,500) options with a weighted average exercise price of $43.46 (2005 – $26.42; 2004 – $20.85). Of the options granted, 1,770,100 (2005 – 2,424,900; 2004 – 843,000) are performance-based options.

As at December 31, 2006, the total liability for expected cash settlements with respect to those options attached with SARs under the LTIP was $371 million (2005 – $382 million; 2004 – $155 million). The current portion of LTIP is included in accounts payable, accrued liabilities and other. As at December 31, 2006, the balance was $345 million (2005 – $343 million; 2004 – $155 million). The long-term portion of LTIP liability is included in asset retirement and other long-term obligations totalling $26 million in 2006 (2005 – $39 million; 2004 – nil). During the year ended December 31, 2006, cash payments of $68 million (2005 – $ 55 million; 2004 – $1 million) were made for 2,511,206 (2005 – 2,655,048; 2004 – 100,125) SARs exercised. Compensation expense totalled $44 million in 2006 (2005 – $173 million; 2004 – $123 million).

At December 31, 2006, the Company had 47,161,116 (2005 – 47,721,018; 2004 – 48,320,985) shares reserved to meet outstanding options for the purchase of common shares.

A summary of the status of the Company's stock option plans as at December 31, 2006, 2005 and 2004, and changes during the years ending on those dates, is presented below:

STOCK OPTIONS	2006		2005		2004	
	Options (thousands)	Weighted Average Exercise Price (dollars)	Options (thousands)	Weighted Average Exercise Price (dollars)	Options (thousands)	Weighted Average Exercise Price (dollars)
Outstanding at beginning of year	**20 966**	**18.70**	18 330	15.12	17 619	12.66
Granted	**4 383**	**43.46**	5 926	26.42	5 090	20.85
Exercised – common shares	**(560)**	**11.43**	(581)	9.78	(3 424)	10.80
Exercised – SARs	**(2 511)**	**16.14**	(2 655)	13.13	(100)	12.82
Forfeited	**(847)**	**17.96**	(54)	20.70	(855)	16.31
Expired	**(24)**	**39.38**	–	–	–	–
Outstanding at year-end	**21 407**	**24.28**	20 966	18.70	18 330	15.12
Options exercisable at year-end	**10 400**		9 594		8 454	

Stock options outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable	
Exercise Price	Number Outstanding (thousands)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (dollars)	Number Exercisable (thousands)	Weighted Average Exercise Price (dollars)
\$7 – \$14	2 515	2.9	9.88	2 515	9.88
\$14 – \$21	8 924	6.3	17.74	6 927	16.84
\$21 – \$28	5 604	8.1	26.38	946	26.38
\$28 – \$35	69	8.5	29.57	11	29.50
\$35 – \$44	4 295	9.2	43.46	1	35.34
	21 407	**7.0**	**24.28**	**10 400**	**16.04**

Note 4. Income Tax

The income tax provision included in the determination of earnings reflects an effective tax rate that is different from the Corporation's statutory tax rate. The following table provides a reconciliation between the effective and statutory rates:

($ millions except as noted)	2006	2005	2004
		(restated)	(restated)
Earnings before income tax	**2 235**	2 767	1 881
Basic corporate tax rate (per cent)	**34.4**	37.0	37.5
Income tax at basic rate	**769**	1 024	705
Increase (decrease) resulting from:			
Crown royalties and other payments to provinces	**41**	102	90
Resource allowance and other abatement measures	**(74)**	(107)	(105)
Manufacturing and processing credit	**(4)**	(3)	(3)
Changes in income tax rates	**(213)**	(30)	(40)
Capital losses not previously recognized	**–**	–	(1)
Tax pools acquired from affiliated company	**–**	(164)	–
Other, including revisions in previous tax estimates	**(22)**	(56)	(49)
Total	**497**	766	597
Effective income tax rates on earnings (per cent)	**22.2**	27.7	31.8

The Corporation's future income tax asset (liability) is comprised of the following tax-affected temporary differences:

($ millions)	2006	2005	2004
		(restated)	(restated)
Current			
LIFO inventory valuation	**182**	205	116
Non-capital losses carryforward	**–**	–	149
Long Term Incentive Plan	**103**	117	46
Employee future benefits	**3**	2	(5)
Asset retirement obligations	**9**	8	9
Other	**2**	(5)	1
Total – current	**299**	327	316
Non-current			
Properties, plant and equipment	**(2 569)**	(1 746)	(1 433)
Employee future benefits	**(105)**	(110)	(93)
Asset retirement obligations	**102**	94	87
Long Term Incentive Plan	**8**	14	7
Other	**22**	15	(16)
Total – non-current	**(2 542)**	(1 733)	(1 448)
Net future income tax liability	**(2 243)**	(1 406)	(1 132)

The Corporation has $94 million in capital losses, which may be offset against future capital gains and may be carried forward indefinitely. The future tax benefit of capital losses has not been recognized.

Note 5. Taxes, Royalties and Other

The following amounts were included in the determination of earnings:

($ millions)	2006	2005	2004
		(restated)	(restated)
Items reported separately:			
Income tax	**497**	766	597
Items included in sales or other operating revenues or in operating, selling and general expenses:			
Crown royalties and mineral taxes	**337**	420	304
Royalties paid to private leaseholders	**59**	74	60
Other taxes	**82**	108	108
Research and development expense	**44**	41	28

Note 6. Total Debt

($ millions)	Issued	Maturity	2006	2005	2004
Short-Term Borrowings			**1 235**	–	–
Medium-Term Notes					
Floating rate notes[1]	Mar 22, 2002	Mar 15, 2005	**–**	–	134
Capital leases		varying dates	**1**	1	3
Mobile equipment lease		varying dates	**199**	210	–
Total Debt			**1 435**	211	137
Included in current			**(1 238)**	(11)	(136)
Total Long-term Debt			**197**	200	1

[1] In 2005, floating rate notes totalling $134 million were repaid.

The Corporation entered into a $1-billion revolving credit facility ("the facility") during the second quarter of 2006. The facility was arranged with a syndicate of banks and matures on June 15, 2008. This facility, along with the already established $1.5 billion commercial paper program, provided the Corporation with $2.5 billion of borrowing capacity. At December 31, 2006, the outstanding balance on the facility was $199 million in the form of short-term borrowings that had an effective interest rate of 4.44 per cent. At December 31, 2006, the outstanding balance on the commercial paper program was $1,036 million at an effective interest rate of 4.39 per cent.

Shell Canada consolidated the variable interest entity that holds the lease arrangements for large mobile equipment at the Athabasca Oil Sands Project's Muskeg River Mine. The mobile equipment lease has terms ranging from one to four years. Interest fluctuates with prime and was paid monthly at rates ranging from 3.79 per cent to 4.82 per cent.

Repayments of obligations necessary during the next four years are as follows:

$ 3 million in 2007
$ 46 million in 2008
$ 103 million in 2009
$ 48 million in 2010.

Note 7. Asset Retirement and Other Long-Term Obligations

($ millions)	2006	2005	2004
		(restated)	(restated)
Asset retirement obligations	**375**	304	282
Other employee future benefits	**155**	143	137
Other obligations	**109**	115	33
	639	562	452
Included in current liabilities	**(28)**	(24)	(35)
Total	**611**	538	417

The change in the asset retirement obligations liability is as follows:

($ millions)	2006	2005	2004
Asset retirement obligations liability at January 1	**304**	282	264
Additions	**35**	17	4
Accretion	**17**	15	14
Revisions in estimated cash flows	**44**	15	20
Settlements	**(25)**	(25)	(20)
Asset retirement obligations liability at December 31	**375**	304	282

The total undiscounted amount of the estimated cash flows required to settle the obligations is $634 million (2005 – $540 million; 2004 – $475 million), which has been discounted using a credit-adjusted risk-free rate of six per cent. The requirement to settle the obligations can occur during the asset's life but most of the obligations will not be settled until the end of the asset's useful life, which can exceed 25 years in some circumstances.

Note 8. Financial Instruments

	Notional Fair Value[1]			Unrealized Gain (Loss)[2]		
($ millions)	**2006**	2005	2004	**2006**	2005	2004
Commodity contracts	**9**	24	43	**(1)**	1	–
Foreign exchange contracts	**–**	7	19	**–**	–	–

	Notional Fair Value[1]			Carrying Value		
($ millions)	**2006**	2005	2004	**2006**	2005	2004
Long-term debt[3]	**–**	–	134	**–**	–	134

[1] Notional fair value is the product of the contract volume and the mark-to-market forward price. Purchase and sales positions have not been offset. Amounts disclosed represent the sum of the absolute values of the positions. The reported amounts of financial instruments such as cash equivalents, marketable securities and short-term debt approximate fair value.

[2] Unrealized gain or loss represents the gain or loss the Corporation would incur if the contract was liquidated at December 31.

[3] Long-term debt includes the current portion of debt.

The Corporation uses commodity contracts to reduce the risk of price fluctuations of some commodities. Over-the-counter contracts with terms generally no longer than one year are used.

At December 31, commodity contracts outstanding were:

	2006		2005		2004	
($ millions except as noted)	Face Value	Volume[1]	Face Value	Volume[1]	Face Value	Volume[1]
Crude oil and refined products commitments	**10**	**113**	22	296	43	810
Electricity commitments	**–**	**5**	1	9	–	–

[1] Crude oil and refined products volumes are expressed as thousands of barrels and electricity is denoted in thousands of megawatt hours.

A portion of the Corporation's cash flow is in U.S. dollars. The U.S. dollar receipts are less than U.S. dollar disbursements primarily due to the cost of foreign crude cargoes exceeding U.S. dollar denominated product sales. The resulting net shortage of U.S. dollars is funded through U.S. dollar spot, forward and swap contracts. These instruments generally mature in less than 30 days. U.S. dollar requirements for significant capital projects and some marketing transactions are funded through forward contracts with maturities generally of less than one year.

Non-performance by the other parties to the financial instruments exposes the Corporation to credit loss. The counterparties for most of the commodity contracts are affiliates of Royal Dutch Shell plc. Other financial instrument contracts are generally with domestic and international banks or corporations, all with credit ratings of A or better. There is no significant concentration of credit risk and Shell does not anticipate non-performance by the counterparties.

Note 9. Employee Future Benefits

Employees initially participate in the defined contribution segment of the Corporation's pension plan. After meeting certain service and age requirements, employees can elect to participate in the defined benefit segment of the pension plan. Benefits from these segments are either partially or fully paid by the Company and are based on years of service and final average earnings. Benefits from the defined benefit segment of the pension plan are indexed for inflation after retirement. In addition to the pension plan, life insurance and supplementary health and dental coverage benefits are provided to retirees. The effective date of the most recent actuarial valuation for funding purposes was December 31, 2006. The next actuarial valuation for funding purposes must be no later than December 31, 2009.

ACCRUED BENEFIT OBLIGATION ($ millions)	**2006**		2005		2004	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Accrued benefit obligation as at January 1	**2 568**	**220**	2 204	168	1 998	182
Current service cost	**47**	**2**	38	1	32	1
Interest cost	**128**	**11**	126	10	118	11
Actuarial loss (gain)	**16**	**9**	41	9	25	(13)
Transfers	**22**	**–**	28	–	25	–
Benefits paid	**(138)**	**(7)**	(134)	(7)	(129)	(7)
Change in assumption	**(71)**	**(6)**	265	39	135	(9)
Plan amendments	**–**	**–**	–	–	–	3
Accrued benefit obligation as at December 31	**2 572**	**229**	2 568	220	2 204	168

Included in the above pension benefits are unfunded amounts for the supplemental pension obligations of $190 million (2005 – $177 million; 2004 – $143 million) and $27 million (2005 – $29 million; 2004 – $29 million) for the supplemental spousal pension obligations.

PLAN ASSETS ($ millions)	**2006**		2005		2004	
Plan assets as at January 1	**2 188**	**–**	1 976	–	1 782	–
Actual return on plan assets	**259**	**–**	232	–	182	–
Employer contributions	**118**	**7**	89	7	119	7
Employee contributions	**4**	**–**	3	–	3	–
Transfers	**22**	**–**	28	–	25	–
Benefits paid	**(138)**	**(7)**	(134)	(7)	(129)	(7)
Expenses	**(8)**	**–**	(6)	–	(6)	–
Fair value as at December 31	**2 445**	**–**	2 188	–	1 976	–
Funded status – deficit	**(127)**	**(229)**	(380)	(220)	(228)	(168)
Unamortized net losses[1]	**705**	**60**	952	60	805	12
Unamortized past service cost	**–**	**2**	–	3	–	3
Unamortized transitional (asset) obligation[2]	**(72)**	**11**	(108)	14	(143)	16
Accrued benefit asset (obligation)[3]	**506**	**(156)**	464	(143)	434	(137)

[1] Unamortized net losses are amortized over the expected average remaining service period of active employees, which is currently nine years (2005 – nine years; 2004 – nine years).

[2] Two years remain in the amortization of the pension benefit transitional asset. Six years remain in the amortization of the other benefit transitional obligation

[3] The accrued benefit asset (obligation) for pension benefits is included in the "investments, long-term receivables and other" line and for other benefits in the "asset retirement and other long-term obligations" line on the Consolidated Balance Sheet.

The percentage of the fair value of total plan assets held at December 31 is as follows:

(per cent)	2006	2005	2004
Equity securities	**58.6**	49.4	46.9
Debt securities	**35.0**	43.8	40.3
Real estate	**4.8**	3.5	3.4
Other	**1.6**	3.3	9.4
Total	**100**	100	100

EXPENSE ($ millions)	2006		2005		2004	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Current service cost	**47**	**2**	38	1	32	1
Employee contributions	**(4)**	**–**	(3)	–	(3)	–
Interest cost	**128**	**11**	126	10	118	11
Plan amendments	**–**	**–**	–	–	–	3
Actual return on plan assets	**(259)**	**–**	(232)	–	(182)	–
Actuarial loss (gain) on accrued benefit obligation	**(55)**	**3**	306	48	160	(22)
Costs arising in the period	**(143)**	**16**	235	59	125	(7)
Differences between costs arising in the period and costs recognized in the period in respect of:						
Return on plan assets	**112**	**–**	95	–	53	–
Actuarial loss (gain)	**143**	**–**	(235)	(47)	(91)	24
Plan amendments	**–**	**–**	–	–	–	(3)
Transitional obligation (asset)	**(36)**	**3**	(36)	2	(36)	2
Net expense for benefit plan	**76**	**19**	59	14	51	16
Defined contribution segment	**25**	**–**	21	–	13	–
Total	**101**	**19**	80	14	64	16

ASSUMPTIONS (per cent)	2006		2005		2004	
Discount rate	**5.20**	**5.20**	5.00	5.00	5.80	5.80
Long-term rate of return on plan assets[1]	**7.00**	**–**	7.25	–	7.25	–
Rate of compensation growth	**4.70**	**4.70**	4.70	4.70	4.70	4.70
Health care trend rate[2]	**–**	**6.73**	–	7.01	–	5.92

[1] The long-term rate of return on plan assets was used in the pension calculation for the fiscal year noted.

[2] The health care trend rate is a weighted average of medical, dental, and provincial health care trend rates, decreasing each year to a rate of 4.0 per cent in 2014 and thereafter.

ASSUMPTIONS SENSITIVITIES ($ millions)	One Per Cent Increase	One Per Cent Decrease
Discount rate		
Effect on pension benefit expense	(34)	42
Effect on accrued benefit obligation	(311)	391
Long-term rate of return on plan assets		
Effect on pension benefit expense	(23)	24
Rate of compensation growth		
Effect on pension benefit expense	13	(11)
Effect on accrued benefit obligation	58	(52)
Health care cost trend rate		
Effect on current service and interest cost	2	(1)
Effect on accrued benefit obligation	24	(20)

Note 10. Transactions with Affiliated Companies

In the course of its regular business activities, Shell Canada enters into routine transactions with affiliates of the Company's majority shareholder. Product purchases and sales are at commercial rates. Service fees, which represent approximately 1.0 per cent of the total related party transactions, are at cost. The amounts paid or received on transactions with Shell International Trading Company and other affiliates of Royal Dutch Shell plc that are reflected in the Consolidated Statement of Earnings are shown in the table below:

($ millions)	**2006**	2005	2004
Purchases of crude oil, petroleum products, chemicals and service agreements	**6 529**	5 507	3 961
Amounts payable in respect of such purchases	**441**	204	393
Sales of natural gas, petroleum products and chemicals	**2 435**	2 343	1 928
Amounts receivable in respect of such sales	**199**	245	215

Royal Dutch Shell plc provides support and technology for operating locations to Shell Canada. Through these service agreements, Shell Canada has access and rights to research and development and technical expertise.

In December 2004, the Corporation purchased the shares of a related party, Coral Resources Canada ULC, for $39 million. The purchase price was established by negotiation with consideration of comparable commercial transactions. As a result of this transaction, Shell Canada acquired non-capital losses to be used against future taxable income. The losses were fully recognized in 2005.

Note 11. Commitments and Contingencies

At December 31, 2006, the Corporation had non-cancellable operating and other long-term commitments with an initial or remaining term of one year or more. Future minimum payments under such commitments are estimated to be:

($ millions)	Operating Commitments[1]	Other Long-Term Commitments[2]
2007	80	1 479
2008	76	977
2009	71	856
2010	67	782
2011	65	782
thereafter	195	11 039[3]

[1] These operating commitments cover leases of service stations, office space and other facilities.

[2] The Corporation has substantial commitments for use of facilities or services and supply and processing of products all made in the normal course of business.

[3] The Corporation has a commitment of $9.0 billion to purchase certain feedstocks from the other joint venture participants in the Athabasca Oil Sands Project (AOSP). This commitment is for the period up to 2028, and is based on the current year pricing premise. Various pipeline charges of $1.2 billion and $0.8 billion of AOSP utilities and hydrogen commitments are also included in the total.

Various lawsuits are pending against the Corporation. Actual liability with respect to these lawsuits is not determinable, but management believes, based on counsels' opinions, that any potential liability will not materially affect the Corporation's financial position.

Note 12. Earnings Per Share

	2006	2005	2004
		(restated)	(restated)
Earnings ($ millions)	**1 738**	2 001	1 283
Weighted average number of common shares (millions)	**825**	825	826
Dilutive securities (millions)			
Options on Long Term Incentive Plan[1]	**8**	9	6
Basic earnings per share (dollars)[2]	**2.11**	2.43	1.55
Diluted earnings per share (dollars)[3]	**2.09**	2.40	1.54

[1] The amount shown is the net number of common shares outstanding after the notional exercise of the share options and the cancellation of the notionally repurchased common shares as per the treasury stock method.

[2] Basic earnings per share is the earnings divided by the weighted average number of common shares.

[3] Diluted earnings per share is the earnings divided by the aggregate of the weighted average number of common shares plus the dilutive securities.

Note 13. Acquisition of BlackRock Ventures Inc.

On June 21, 2006, the Corporation acquired more than 92 per cent of the outstanding common shares of BlackRock Ventures Inc. (BlackRock). The original offer was extended to June 27, 2006 and again to July 10, 2006 and additional common shares were acquired. The Corporation completed its acquisition of BlackRock and acquired all of the remaining common shares by way of compulsory acquisition on July 11, 2006. BlackRock was engaged in the development and production of heavy oil in Western Canada.

The Corporation's total consideration for the transaction was $2,570 million ($2,428 million net of cash acquired) including acquisition costs of $12 million and working capital of $108 million.

The acquisition was accounted for based on the purchase method and the allocation was supported by a third party valuation. A summary of the purchase equation is presented as follows:

Net assets acquired ($ millions)	
Oil and natural gas properties	**3 092**
Goodwill[1]	**234**
Working capital[2]	**108**
Other assets	**1**
Asset retirement obligations	**(11)**
Future income tax liability	**(854)**
	2 570

[1] The $234 million of goodwill has no tax basis and was allocated to the Oil Sands business unit.

[2] Working capital acquired includes cash of $142 million.

Note 14. United States Generally Accepted Accounting Principles and Reporting Practices

The financial statements have been prepared in accordance with accounting principles generally accepted in Canada. They differ from those generally accepted in the United States in the following respects:

Capitalization of Interest Interest costs were expensed as incurred. U.S. accounting principles require capitalization and subsequent amortization of certain interest costs incurred on capital outlays.

Pension Expenses Prior to 2000, the application of the corridor method of accounting for pension expense used in the U.S. accounting principles resulted in the amortization of gains and losses only if a 10 per cent threshold was exceeded. On January 1, 2000, a new accounting standard was adopted, which harmonized Canadian and U.S. accounting standards. Adoption of the new Canadian standard gave rise to a transition asset, which is being amortized over the expected average remaining service life of the employee group. This amount is not recognized for U.S. reporting purposes.

Shell Canada adopted Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (FAS) Number 158 – *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132(R)*, which is effective for fiscal years ending after December 15, 2006. The statement requires the entity to recognize in its balance sheet the overfunded or underfunded status of a defined benefit postretirement plan measured as the difference between the fair value of plan assets and the benefit obligation as well as additional disclosure requirements for individual line items such as liability for pension benefits, deferred income taxes, total liabilities, accumulated other comprehensive income and total shareholders' equity on a before and after application of Statement 158.

Derivative Instruments and Hedging Activity FASB Statement No. 133 requires that hedging activity that does not qualify as a hedge be mark-to-market and charged to earnings.

Stock-Based Compensation FASB Statement No. 123 requires performance-based options to be charged to earnings. Shell Canada adopted the new Canadian standard requiring the expensing of stock options prospectively in 2003.

In December 2004, FASB Statement No. 123(R) *Stock-Based Payment* was issued. Pursuant to the U.S. Securities and Exchange Commission's (SEC) Final Rule Release dated April 21, 2005, registrants that are not a small business issuer are required to prepare financial statements in accordance with FASB Statement No. 123(R) beginning with the first interim or annual reporting period of the registrant's first fiscal year beginning on or after June 15, 2005. Effective for 2006, all stock options are accounted for using the fair value method. The impact of the adoption of this standard was dependent upon a number of valuation factors including the share price at December 31, 2006.

In 2006, the Company adopted EIC-162 (see Note 1), which resulted in 2004 and 2005 earnings being restated. Under FAS 123(R), this accounting treatment has been followed prospectively from January 1, 2006, and therefore U.S. GAAP earnings for 2004 and 2005 have not been restated.

BlackRock Acquisition Federal tax rate reductions had been substantially enacted at the time of the BlackRock acquisition but not yet enacted. This gave rise to a difference in the accounting for the BlackRock acquisition under U.S. GAAP versus Canadian GAAP, whereby goodwill and future income tax would both be higher by $81 million at the date of acquisition. Following the acquisition, the tax rate changes were enacted totalling $81 million.

If the Corporation's financial statements had been presented on the basis of U.S. accounting principles, earnings and earnings per share would have been:

($ millions)	2006	2005	2004
		(restated)	(restated)
Earnings	**1 738**	2 001	1 283
Increase (decrease):			
Capitalized interest amortized	**(1)**	(4)	(15)
Pension expense	**13**	12	(1)
Operating expense and fair value of derivative instruments	**–**	(19)	21
Depreciation expense	**(9)**	(10)	(25)
BlackRock acquisition	**81**	–	–
Interest expense	**–**	6	(6)
Stock-based compensation	**(50)**	20	10
Income taxes	**16**	(2)	9
Adjusted earnings attributable to common shares	**1 788**	2 004	1 276
Other comprehensive income	**254**	(82)	(3)
Total comprehensive income	**2 042**	1 922	1 273
Basic earnings per common share (dollars)	**2.17**	2.43	1.54
Diluted earnings per common share (dollars)	**2.15**	2.40	1.53

In accordance with U.S. accounting standard FAS 130, a separate statement would be presented which discloses the components of other comprehensive income:

($ millions)	2006	2005	2004
Accumulated other comprehensive income (loss), beginning of year	**(254)**	(172)	(169)
Increase (decrease):			
Minimum additional pension liability	**383**	(123)	(2)
Minimum additional pension liability – tax	**(129)**	41	(1)
Other comprehensive income (loss)	**–**	(254)	(172)
FAS 158 Adjustments			
Adjustment on adoption of FAS 158	**(536)**	–	–
Adjustment on adoption of FAS 158 – tax	**159**	–	–
Accumulated other comprehensive income (loss)	**(377)**	(254)	(172)

Note 14. United States Generally Accepted Accounting Principles and Reporting Practices (continued)

On December 31, 2006, there was a one-time adjustment for the application of FAS 158 on both the Defined Benefit (DB) plan and Other Postretirement Employee Benefits (OPEB) plan. Separate disclosure of components not yet reflected in Net Periodic Benefit Cost and included in accumulated other comprehensive income:

($ millions)	2006 DB	2006 OPEB
Increase (decrease):		
Transitional asset (obligation)	–	(12)
Past Service credit (cost)	–	(2)
Net actuarial gain (loss)	(462)	(60)
Net actuarial loss – tax	137	22
Accumulated other comprehensive income (loss)	(325)	(52)
Cumulative employer contributions in excess of net periodic benefit cost	335	(155)
Deferred Tax Asset (liability)	(137)	(22)
Net asset (liability) amount recognized in Statement of Financial Position	(127)	(229)

There are no material differences on the Corporation's Consolidated Statement of Cash Flows.

The net effect of the differences on the Corporation's Consolidated Balance Sheet is not material except for the following:

From 1996, there is $225 million of retained earnings as a result of the sale of the Chemicals business. This would be classified as contributed surplus since this was a related party transaction.

In 2005, to comply with FAS 87, the prepaid pension asset was adjusted by an additional minimum liability amount. FAS 87 required this adjustment to reflect the excess of the plan's accumulated benefit obligation over the market value of the plan assets. This excess over market value was the cumulative result of weakening equity markets in prior years and a decline in bond yields used to determine the discount rate. In 2005, the additional minimum liability of $383 million (2004 – $260 million) was reflected as a reduction of pension assets, with a corresponding reduction of the Company's future income tax liability of $129 million (2004 – $88 million.)

As disclosed on page 74, the adoption of FAS 158 has affected the net liability position.

In compliance with FASB Interpretation Number 46R, which relates to Variable Interest Entities (VIEs), assets for 2004 would have increased by $200 million and liabilities would have increased by $212 million. Under Canadian GAAP, Shell Canada's VIE was consolidated on January 1, 2005, and therefore resulted in no GAAP difference for 2005 or 2006.

Supplemental Oil Products Disclosure

Year ended December 31 (unaudited)

PRODUCTION (thousands of cubic metres/day)	**2006**	2005	2004
Crude oil processed by Shell refineries			
Montreal East (Quebec)	**18.3**	18.6	17.6
Sarnia (Ontario)	**9.6**	10.4	10.9
Scotford (Alberta)[1]	**16.7**	15.9	16.6
Total	**44.6**	44.9	45.1
Rated refinery capacity at year-end			
Montreal East (Quebec)	**20.7**	20.7	20.7
Sarnia (Ontario)	**12.2**	12.0	12.0
Scotford (Alberta)	**19.0**	18.9	17.7
Total	**51.9**	51.6	50.4

SALES (thousands of cubic metres/day)	**2006**	2005	2004
Gasolines	**20.8**	21.0	20.9
Middle distillates	**20.0**	21.0	19.2
Other products	**6.5**	7.1	7.4
Total	**47.3**	49.1	47.5

	2006	2005	2004
Refinery utilization (per cent)[2]	**86**	87	89
Earnings per litre (cents)[3]	**3.4**	2.4	2.6

[1] Crude oil processed by Shell refineries includes upgrader feedstock supplied to Scotford Refinery.

[2] Refinery utilization equals crude oil processed by Shell refineries divided by total capacity of Shell refineries, including capacity uplifts at Scotford Refinery due to processing of various streams from the upgrader.

[3] Oil Products earnings per litre equals Oil Products earnings after-tax divided by total Oil Products sales volumes.

Supplemental Exploration & Production Disclosure[1]

Year ended December 31 (unaudited)

PRODUCTION[2]	2006	2005	2004
Natural gas (millions of cubic feet/day)			
Gross	**523**	512	540
Net	**425**	413	449
Ethane, propane and butane (thousands of barrels/day)			
Gross	**19.8**	23.3	25.1
Net	**15.9**	18.6	19.9
Condensate (thousands of barrels/day)			
Gross	**13.0**	15.3	15.2
Net	**10.1**	11.8	11.8
Sulphur (thousands of long tons/day)			
Gross	**5.2**	5.3	5.6
Net	**5.0**	4.8	4.9

SALES[3]	2006	2005	2004
Natural gas – gross (millions of cubic feet/day)	**514**	510	536
Ethane, propane and butane – gross (thousands of barrels/day)	**34.1**	38.2	44.0
Condensate – gross (thousands of barrels/day)	**20.6**	18.1	19.1
Sulphur – gross (thousands of long tons/day)	**11.9**	11.7	11.3

PRICES	2006	2005	2004
Natural gas average plant gate netback price ($/mcf)	**6.79**	8.23	6.49
Ethane, propane and butane average field gate price ($/bbl)	**33.94**	34.79	28.71
Condensate average field gate price ($/bbl)	**71.63**	66.76	50.46

[1] Effective January 1, 2006, the Peace River business was transferred from Exploration & Production (E&P) to the Oil Sands business unit. Prior period amounts have been adjusted for this transfer.

[2] Gross production includes all production attributable to Shell's interest before deduction of royalties; net production is determined by deducting royalties from gross production.

[3] Sales volumes include own production, inventory and brokered third party sales.

EXPLORATION AND DEVELOPMENT WELLS DRILLED	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploration						
Gas	**2**	**2**	4	2	3	1
Oil	**–**	**–**	–	–	–	–
Dry	**3**	**3**	5	3	4	2
	5	**5**	9	5	7	3
Development						
Gas	**13**	**9**	11	7	10	8
Dry	**1**	**1**	–	–	1	–
	14	**10**	11	7	11	8
Total wells drilled	**19**	**15**	20	12	18	11
Wells in progress	**36**	**26**	17	14	13	9

Exploration wells – Wells drilled either in search of new and as yet undiscovered pools of oil or gas, or with the expectation of significantly extending the limits of established pools. All other wells are development wells.

PRODUCTIVE WELLS	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Gas wells						
Alberta	**293**	**235**	274	224	259	215
British Columbia	**1**	**1**	1	1	–	–
Nova Scotia	**19**	**6**	18	6	15	5
Total productive wells [1]	**313**	**242**	293	231	274	220

Productive wells – Producing and non-unitized wells capable of producing.

Gross wells – The number of wells in which Shell Canada has a working interest.

Net wells – The aggregate of the numbers obtained by multiplying each gross well by the percentage working interest of Shell Canada therein, rounded to the nearest whole number.

[1] Multi-completion wells totalled 60 in 2006 (2005 – 55; 2004 – 48).

RESERVES

The Corporation's reserves disclosure and related information have been prepared in reliance on a decision of the applicable Canadian securities regulatory authorities under National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101), which permits the Corporation to present its reserves disclosure and related information in accordance with the applicable requirements of the United States Financial Accounting Standards Board (FASB) and the United States Securities and Exchange Commission (SEC). This disclosure differs from the corresponding information required by NI 51-101. If Shell Canada had not received the decision, it would be required to disclose proved plus probable oil and gas reserves estimates based on forecast prices and costs and information relating to future net revenue using forecast prices and costs.

Reserves estimates are prepared by the Corporation's internal qualified reserves evaluators. No independent qualified reserves evaluator or auditor was involved in the preparation of the Corporation's reserves data. An external, independent petroleum consulting firm audited 100 per cent of the proved oil and gas reserves estimates prepared by the Corporation's internal reserves evaluators and verified compliance with applicable FASB and SEC requirements.

Effective January 1, 2006, the Peace River business was transferred from Exploration & Production to the Oil Sands business unit. Prior period E&P amounts have been adjusted to exclude Peace River operations.

Reserves Quantity Information

Estimation of reserves quantities is based on established geological and engineering principles and involves judgmental interpretation of reservoir data. These estimates are subject to revision as additional information from drilling, seismic, production performance and technology becomes available, as economic and operating conditions change, or as properties are divested or acquired. The difference between the gross and net reserves is the volume dedicated to meet royalty payments over the life of the reserves. The net reserves in the table below have been calculated on the basis of royalty rates and economic conditions in place as at year-end. Shell Canada's estimated proved reserves exclude quantities in the Mackenzie Delta and Arctic Islands, or that otherwise may have been discovered but not yet proved.

OIL, GAS AND OTHER RESERVES

Net proved developed and undeveloped reserves
Beginning of year
Revisions of previous estimates
Extensions, discoveries and other additions
Improved recovery methods
Purchases of reserves in place
Sales of reserves in place
Production
End of year
Net proved developed reserves
End of year
Gross proved developed and undeveloped reserves
End of year
Gross proved developed reserves
End of year

Proved reserves – Estimated quantities of natural gas, natural gas liquids, and sulphur that geological engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs. These estimates are based on existing economic and operating conditions (prices, costs, royalties and income taxes) as at year-end.

Proved developed reserves – Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Natural Gas

In 2006, total net natural gas proved reserves decreased after production of 155 billion cubic feet (bcf) by 93 bcf to 1,092 bcf from 1,185 bcf in 2005. Additions of 101 bcf due to extensions and discoveries included an additional booking of 72 bcf attributed to the continued drilling success in the basin-centred gas region. The balance of these additions resulted from continued exploration success in northeast British Columbia and development drilling in the Panther River and Jumping Pound regions. These additions were offset by a net reduction of 36 bcf due to technical and economic revisions. The main components of these revisions were an increase of 29 bcf in the Sable Offshore Energy Project for the Alma field resulting from new data obtained in 2006, a decrease of 51 bcf in the Tay River field following disappointing drilling results that were announced in November 2006, and a net reduction of 61 bcf for the balance of the E&P portfolio. Reductions due to technical factors were offset partially by positive economic revisions of 47 bcf attributed to the decrease in natural gas royalties due to lower year-end 2006 gas prices relative to 2005. The unitization of a portion of the Waterton gas pool decreased the reserves by an additional 3 bcf.

Natural Gas Liquids

Production of 9 million barrels was partially offset by positive technical and economic revisions of four million barrels resulting in a year-end 2006 net proved reserves position of 49 million barrels.

Sulphur

Net sulphur reserves decreased by 3 million tonnes resulting in a year-end 2006 net proved reserves of 11 million tonnes. This reduction in reserves is a result of the technical revision in the Tay River field in addition to the 2006 production.

NATURAL GAS (billions of cubic feet)			NATURAL GAS LIQUIDS (millions of barrels)			SULPHUR (millions of long tons)		
2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
1 185	1 239	1 365	**54**	62	77	**14**	14	13
(36)	(44)	(51)	**4**	3	(4)	**(1)**	–	1
101	135	122	**–**	–	1	**–**	2	2
–	–	4	**–**	–	–	**–**	–	–
–	6	–	**–**	–	–	**–**	–	–
(3)	–	(37)	**–**	–	–	**–**	–	–
(155)	(151)	(164)	**(9)**	(11)	(12)	**(2)**	(2)	(2)
1 092	1 185	1 239	**49**	54	62	**11**	14	14
689	752	893	**37**	44	54	**8**	10	10
1 400	1 592	1 595	**61**	71	78	**11**	14	14
885	1 026	1 160	**45**	57	68	**8**	10	11

Proved undeveloped reserves – Reserves that are expected to be recovered from new wells on undrilled acreage adjacent to producing acreage, or from existing wells where further significant expenditure is required.

Gross proved reserves – Reserves estimates before the deduction of royalty interests owned by others.

Net proved reserves – Reserves estimates after deduction of royalties and, therefore, only those quantities that Shell has a right to retain.

Supplemental Oil Sands Disclosure[1]

Year ended December 31 (unaudited)

PRODUCTION[2] (thousands of barrels/day)	**2006**	2005	2004
Bitumen – gross			
Minable	**82.5**	95.9	81.3
In situ	**12.4**	8.9	8.1
Total	**94.9**	104.8	89.4
Bitumen – net			
Minable	**81.7**	95.0	80.5
In situ	**12.0**	8.7	7.9
Total	**93.7**	103.7	88.4

SALES[3] (thousands of barrels/day)	**2006**	2005	2004
Synthetic crude sales excluding blend stocks	**85.9**	99.4	83.7
Purchased upgrader blend stocks	**35.4**	37.1	38.2
Total synthetic crude sales	**121.3**	136.5	121.9
Bitumen product excluding diluent	**13.1**	9.9	8.8
Purchased diluent	**3.0**	1.9	2.2
Total bitumen products	**16.1**	11.8	11.0
In situ condensate	**2.7**	2.4	0.8

UNIT COSTS[4] ($/bbl)	**2006**	2005 (restated)	2004 (restated)
Mining and upgrading operations			
Cash operating cost – excluding natural gas ($/bbl)	**23.49**	17.14	17.81
– natural gas ($/bbl)	**5.24**	6.08	5.53
Total cash operating cost ($/bbl)	**28.73**	23.22	23.34
Depreciation, depletion and amortization ($/bbl)	**5.53**	5.77	5.59
Total unit cost ($/bbl)	**34.26**	28.99	28.93
In situ operations			
Cash operating cost – excluding natural gas ($/bbl)	**14.02**	13.65	10.38
– natural gas ($/bbl)	**5.85**	9.56	8.30
Total cash operating cost ($/bbl)	**19.87**	23.21	18.68
Depreciation, depletion and amortization ($/bbl)	**7.85**	5.11	4.10
Total unit cost ($/bbl)	**27.72**	28.32	22.78

1 Effective January 1, 2006, the Peace River business was transferred to Oil Sands from the Exploration & Production business unit. Prior period amounts have been restated to include Peace River operations.

2 Gross production includes all production attributable to Shell's interest before deduction of royalties; net production is determined by deducting royalties from gross production.

3 Sales volumes include third party and inter-segment sales.

4 Total unit cost, including unit cash operating and unit depreciation, depletion and amortization (DD&A) costs, does not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and therefore may not be comparable with the calculation of similar measures for other companies.

Unit cash operating cost for Oil Sands mining and upgrading is defined as: operating, selling and general expenses plus cash cost items included in cost of goods sold (COGS), divided by synthetic crude sales excluding blend stocks. Operating, selling and general expenses associated with mining and upgrading were $725 million in 2006. Cash cost items included in COGS were $176 million.

Unit cash operating cost for in situ operations is defined as: operating, selling and general expenses plus inter-segment purchases of natural gas, divided by bitumen product sales excluding diluent. Operating, selling and general expenses associated with in situ operations were $67 million in 2006. Inter-segment purchases of natural gas were $28 million in 2006.

Unit DD&A cost for Oil Sands mining and upgrading is defined as: DD&A cost divided by synthetic crude sales excluding blend stocks. Unit DD&A cost includes preproduction costs, which were written off over the first three years of the project life (2003 – 2005).

Unit DD&A cost for in situ operations is defined as: DD&A cost divided by bitumen product sales excluding diluent.

PRICES ($/bbl)	**2006**	2005	2004
Synthetic crude average plant gate price	**61.32**	57.55	44.67

EXPLORATION AND DEVELOPMENT WELLS DRILLED	**2006**		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploration						
Bitumen	**3**	**3**	–	–	–	–
Development						
Gas	**–**	**–**	1	1	–	–
Bitumen	**110**	**91**	9	9	–	–
Total development wells drilled	**110**	**91**	10	10	–	–
Total wells drilled	**113**	**94**	10	10	–	–
Wells in progress	**8**	**8**	35	35	–	–

Exploration wells – Wells drilled either in search of new and as yet undiscovered pools of oil or gas, or with the expectation of significantly extending the limits of established pools. All other wells are development wells.

PRODUCTIVE WELLS	**2006**		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Bitumen wells						
Alberta	**295**	**239**	65	65	58	58
Gas wells						
Alberta	**3**	**3**	2	2	1	1
Total productive wells	**298**	**242**	67	67	59	59

Productive wells – Producing and non-unitized wells capable of producing.

Gross wells – The number of wells in which Shell Canada has a working interest.

Net wells – The aggregate of the numbers obtained by multiplying each gross well by the percentage working interest of Shell Canada therein, rounded to the nearest whole number.

RESERVES

The Corporation's bitumen reserves disclosure and related information have been prepared in reliance on a decision of the applicable Canadian securities regulatory authorities under National Instrument NI 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101), which permits the Corporation to present its reserves disclosure and related information in accordance with the applicable requirements of the FASB and the SEC. If Shell had not received the decision, it would be required to disclose (i) minable bitumen reserves estimates based on forecast prices and costs and information relating to future net revenue using constant and forecast prices and costs; and (ii) in situ proved plus probable bitumen reserves based on forecast prices and costs and information relating to future net revenue using forecast prices and costs.

Reserves estimates are prepared by the Corporation's internal qualified reserves evaluators. For 2006, in situ reserves estimates associated with the BlackRock Ventures Inc. properties were prepared by an independent qualified reserves evaluator. With the exception of the BlackRock properties, no independent qualified reserves evaluator or auditor was involved with the preparation of the Company's annual reserves data.

During 2006, the Company elected to obtain a report of an external, independent petroleum consulting firm on the Company's reserves assessment of the Expansion 1 mining project (described next page). This report's estimate of proved and probable reserves was not materially different from the estimate prepared by Shell's Chief Mining Engineer.

Minable

Shell's surface minable development on Lease 13 commenced with the startup of the Muskeg River Mine in 2003. The Muskeg River Mine was designed for an average bitumen production level of 155,000 barrels per day. Building from the base Muskeg River Mine operation, an investment decision was taken in 2006 to advance a 100,000 barrel per day expansion project with target commercial production in 2010. Shell's proved and probable reserves accessed by this expanded development include those from the areas to the west of the Muskeg River where mining operations began, as well as reserves associated with the Expansion 1 project that are located on Lease 13 to the east of Jackpine Creek. This is defined as the Jackpine mine area.

Shell's reserves estimates are based upon a detailed geological assessment including drilling and laboratory tests. They also consider current mine plans, planned operating life and regulatory constraints. The proved plus probable reserves are within development areas covered by approvals by the Alberta Energy and Utilities Board. The reserves estimates are based on the actual barrels of bitumen to be shipped for processing in the expanded Scotford Upgrader. No allowance for volume losses during upgrading is required because of the Scotford Upgrader's hydroconversion upgrading process.

Drilling density is a factor in classifying reserves as either proved or probable. Proved reserves of bitumen are based on drill hole spacing of less than 350 metres. Probable reserves of bitumen are based on drill hole spacing of less than 700 metres. Classification of both proved and probable reserves of bitumen possesses a high degree of geological certainty and is predicated on the application of commercial mining, bitumen extraction and froth cleanup technology.

The largest change for 2006 is the reserves addition associated with the Athabasca Oil Sands Project Expansion 1 project. Following the final investment decision in November 2006, the Company booked 778 million barrels on a gross basis to reflect the defined mining area attributed to the expansion project. At the design rates, this translates to an economic life of 38 years. Of this, 497 million barrels are classified as proved and 281 as probable. In the base Muskeg River Mine are additional drilling and a modest extension of the west pit resulted in a reserves addition of 11 million barrels. As well, a technical revision was made to reclassify 17 million barrels to the proved from probable category. Production accounted for the other change made to the total proved and probable reserves in 2006.

Taking into account both the base Muskeg River Mine and expansion reserves, Shell's interest is a total of 1,292 million barrels proved and 403 million barrels probable reserves for a total of 1,695 million barrels. This estimate is before deduction of royalty barrels. Under the *Oil Sands Royalty Regulation 1997*, royalties depend on project cash flows. Therefore, the calculation of royalties depends on price, production rates, capital costs and operating costs over the life of the development. Using 2006 year-end pricing, net reserves would be 1,134 million barrels of proved and 341 million barrels of probable reserves.

In Situ

The Company's net bitumen reserves from in situ recovery (non-mining) projects increased from 28 million barrels in 2005 to 91 million barrels in 2006 due mainly to the addition of 68 million barrels from the acquisition of BlackRock. Two million barrels of reserves in the Lloydminster area were subsequently divested prior to year-end. The majority of these additions are attributed to the Seal and Orion asset areas which contributed 28 million and 34 million barrels, respectively, to the year-end position. In accordance with U.S. SEC requirements, the Company booked proved reserves for only the first approved phase of the Orion project. Reserves for the future phases will be booked upon final investment decision. Further reserve additions resulting from infill drilling in the Peace River field were offset by production of four million barrels and minor technical and economic revisions.

OIL SANDS MINABLE RESERVES

	MINABLE BITUMEN (millions of barrels)		
	2006	2005	2004
Gross proved reserves			
Beginning of year	**808**	621	651
Revisions of previous estimates	**17**	222	–
Additions	**497**	–	–
Production	**(30)**	(35)	(30)
End of year	**1 292**	808	621
Gross probable reserves			
Beginning of year	**128**	350	350
Revisions of previous estimates	**(17)**	(222)	–
Additions	**292**	–	–
End of year	**403**	128	350
Gross proved and probable reserves	**1 695**	936	971
Net proved reserves	**1 134**	746	615
Net probable reserves	**341**	119	347
Net proved and probable reserves	**1 475**	865	962

Proved reserves – The quantity of proved reserves is computed from dimensions revealed in outcrops, trenches, workings or drill holes. Grade and/or quality are computed from the results of detailed sampling. The sites for inspection, sampling and measurement are spaced so closely and the geological character is so well defined that size, shape, depth and mineral content of the reserves are well established.

Probable reserves – The quantity and grade and/or quality of probable reserves are computed from information similar to that used for proved reserves. However, the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. Although the degree of assurance is less than that for proved reserves, it is sufficient to assume continuity between points of observation.

OIL SANDS IN SITU RESERVES

	IN SITU BITUMEN (millions of barrels)		
	2006	2005	2004
Net proved developed and undeveloped reserves			
Beginning of year	**28**	–	167
Revisions of previous estimates	**(7)**	31	(164)
Extensions, discoveries and other additions	**8**	–	–
Purchases of reserves in place	**68**	–	–
Sales of reserves in place	**(2)**	–	–
Production	**(4)**	(3)	(3)
End of year	**91**	28	–
Net proved developed reserves			
End of year	**42**	11	–
Gross proved developed and undeveloped reserves			
End of year	**96**	28	–
Gross proved developed reserves			
End of year	**45**	11	–

The definitions for proved reserves are as indicated for the E&P disclosure on pages 80 to 81.

Supplemental Landholdings Disclosure

As at December 31 (unaudited)

	UNDEVELOPED				DEVELOPED			
	2006		2005		**2006**		2005	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Onshore within the provinces								
Conventional oil and gas:								
Alberta	**298**	**156**	294	151	**536**	**378**	551	388
British Columbia	**317**	**213**	316	221	**–**	**–**	–	–
Quebec	**5**	**–**	5	–	**–**	**–**	–	–
Coal bed methane:								
Alberta	**23**	**23**	24	24	**–**	**–**	–	–
British Columbia[1]	**796**	**796**	1 043	1 043	**–**	**–**	–	–
Basin-Centred Gas								
Alberta	**219**	**179**	118	114	**11**	**5**	–	–
British Columbia	**100**	**89**	70	70	**–**	**–**	–	–
Bitumen:								
– mining[2]	**251**	**243**	199	189	**11**	**7**	11	7
– in situ	**441**	**320**	87	87	**95**	**78**	18	18
	2 450	**2 019**	2 156	1 899	**653**	**468**	580	413
Canada Lands								
Beaufort	**247**	**247**	–	–	**–**	**–**	–	–
Offshore Nova Scotia	**517**	**198**	517	198	**109**	**34**	109	34
Orphan Basin	**5 249**	**1 050**	5 249	1 050	**–**	**–**	–	–
Northwest Territories	**65**	**55**	65	55	**–**	**–**	–	–
Offshore West Coast	**13 590**	**12 845**	13 590	12 845	**–**	**–**	–	–
Nunavut Territory	**5 801**	**3 100**	5 801	3 100	**–**	**–**	–	–
Beaver River	**1**	**–**	1	–	**–**	**–**	–	–
	25 470	**17 495**	25 223	17 248	**109**	**34**	109	34
Total	**27 920**	**19 514**	27 379	19 147	**762**	**502**	689	447

[1] In 2006, approximately 220,000 acres were returned to the lessor as part of a condition to the lease. Shell does not estimate that this will impact the development plan for coal bed methane.

[2] Mining net undeveloped landholdings includes options by other parties not yet exercised.

Gross acres include the interests of others; net acres exclude the interests of others.

Developed lands are leases and other forms of title documents issued by owners or legislative authorities that contain a well, or are in close proximity to other lands that contain a well that has been drilled or completed to a point that would permit production of commercial quantities of oil and gas.

Undeveloped lands are all lands that are not developed and that retain exploration rights.

Supplemental Financial Data and Quarterly Stock-Trading Information

Year ended December 31 (unaudited)

DATA PER COMMON SHARE (dollars except as noted)	2006	2005	2004
		(restated)	(restated)
Earnings – basic	2.11	2.43	1.55
Earnings – diluted	2.09	2.40	1.54
Dividends	0.440	0.367	0.313
Common shareholders' equity	11.61	9.94	7.90
Common shares outstanding at year-end (millions)	825	825	826
Registered shareholders (number at year-end)	2 306	2 361	2 454

RATIOS	2006	2005	2004
		(restated)	(restated)
Return on average common shareholders' equity (per cent)[1]	19.6	27.2	21.3
Return on average capital employed (per cent)[2]	18.2	26.7	19.9
Common share dividends as percentage of earnings[3]	20.9	15.1	20.2
Price to earnings ratio[4]	20.6	17.3	17.2
Current assets to current liabilities	0.6	1.3	0.9
Interest coverage[5]	54.2	252.5	73.5
Reinvestment ratio (per cent)[6]	92.7	56.5	44.7
Total debt as percentage of capital employed[7]	13.0	2.5	2.1
Debt to cash flow (per cent)[8]	54.9	6.9	6.4
U.S. GAAP earnings to fixed charges ratio[9]	33.1	69.8	33.5

[1] Earnings divided by average common shareholders' equity.

[2] Earnings plus after-tax interest expense divided by average of opening and closing capital employed. Capital employed is a total of equity, long-term debt and short-term borrowings.

[3] Common share dividends paid divided by earnings.

[4] Closing share price at December 31 divided by earnings per share.

[5] Pretax earnings plus interest expense divided by interest expense.

[6] Capital, exploration, predevelopment and investment expenditures divided by cash flow from operations.

[7] Total debt divided by total debt plus equity.

[8] Total debt divided by cash flow from operations.

[9] Earnings consists of pretax income from continuing operations plus fixed charges less interest capitalized. Fixed charges consists of expensed and capitalized interest plus interest within rental expenses.

EMPLOYEES	2006	2005	2004
Employees (number at year-end)	4 793	4 564	4 003

STOCK-TRADING INFORMATION	2006					2005				
	Quarter				Total	Quarter				Total
	1st	2nd	3rd	4th	Year	1st	2nd	3rd	4th	Year
Share prices (dollars)[1]										
High	47.19	45.99	42.50	43.85	47.19	31.67	34.39	41.62	42.35	42.35
Low	37.33	37.15	29.51	28.90	28.90	25.11	26.84	33.30	32.45	25.11
Close (end of period)	41.05	41.50	31.35	43.51	43.51	29.00	32.89	40.65	42.05	42.05
Shares traded (thousands)[1]	28 000	24 311	30 262	85 578	168 151	32 017	21 961	22 362	23 719	100 059

[1] Toronto Stock Exchange quotations.

Corporate Directory and Board of Directors

OFFICERS *(all in Calgary)*

Clive Mather
President and Chief Executive Officer

Cathy L. Williams
Chief Financial Officer

VICE PRESIDENTS

David C. Aldous
Senior Vice President, Oil Products

H. Ian Kilgour
Senior Vice President, Exploration & Production

Brian E. Straub
Senior Vice President, Oil Sands

Timothy J. Bancroft
Vice President, Sustainable Development, Technology and Public Affairs

Graham Bojé
Vice President, Manufacturing and Supply

David R. Brinley
Vice President, General Counsel & Secretary

David R. Collyer
Vice President, Frontier

Ramzi Fawaz
Vice President, Projects, Oil Sands

R. David Fulton
Vice President, Human Resources

Rob W.P. Symonds
Vice President, Foothills

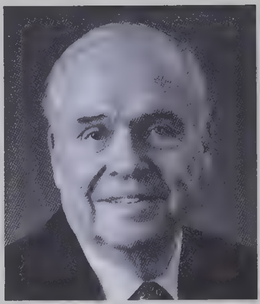
Thomas G. Zengerly
Vice President, Operations, Oil Sands

TREASURER

Matthew B. Haney

CONTROLLER

Donna Tarka



Derek H. Burney, O.C.[3] [5] [6] [7]
Ottawa, Ontario

Lead Director

Chair of the Nominating and Governance Committee and the Special Committee

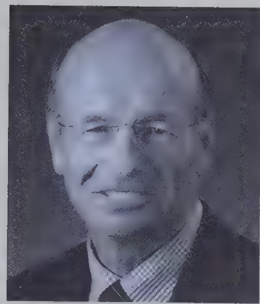
On the Board of Directors since April 25, 2001.

Since 2006, Mr. Burney has been the Chairman of CanWest Global Communications Corp., an international media company with interests in broadcast television, publications, radio, specialty cable channels, out-of-home advertising and interactive operations in Canada, Australia, New Zealand, Malaysia, Singapore, Indonesia, Turkey, the United Kingdom and the United States. Also in 2006, Mr. Burney was appointed as Senior Strategic Advisor to Ogilvy Renault LLP, a full service law firm with offices in Toronto, Ottawa, Montreal and London, United Kingdom. Mr. Burney assists clients in dealing with cross-border and domestic issues as well as trade and investment policy matters. Since 2004, Mr. Burney has been the Chairman of New Brunswick Power Corporation, a Crown corporation with the legislated mission to provide for the electricity needs of the Province of New Brunswick. New Brunswick Power Corporation is the largest electric utility in Atlantic Canada. From 1999 to 2004, Mr. Burney served as President and Chief Executive Officer of CAE Inc., the world's premier provider of simulation and control technologies for training and optimization solutions for the aerospace and defence sectors. He is Chairman of the Confederation College Foundation, a Fellow at the Canadian Defence and Foreign Affairs Institute and a visiting professor and Senior Distinguished Fellow of Carleton University. Mr. Burney also serves as a director of TransCanada Corporation and TransCanada Pipelines Limited.

Louise Fréchette, O.C. (3) (6)
Montreal, Quebec

On the Board of Directors since September 28, 2006.

Ms. Fréchette most recently served as Deputy Secretary-General of the United Nations from 1998 to 2006. From 1995 until 1998, she was Deputy Minister of the Canadian federal Department of Defence. Prior to 1995, Ms. Fréchette held a succession of senior positions in the federal government, including Associate Deputy Minister of the Department of Finance, Ambassador and Permanent Representative of Canada to the United Nations, Assistant Deputy Minister positions with the Department of Foreign Affairs and International Trade, and Canada's Ambassador to Argentine and Uruguay. Ms. Fréchette is also a Distinguished Fellow of the Centre for International Governance Innovation in Waterloo, Ontario.



David A. Galloway (1) (2)
Toronto, Ontario

On the Board of Directors since September 28, 2006.

Mr. Galloway is currently Chairman of the Board of the Bank of Montreal and was President and Chief Executive Officer of Torstar Corporation from 1988 until his retirement in 2002. He joined Torstar Corporation in 1981 as Director of Corporate Development. Torstar Corporation is a major newspaper and book publishing company. It publishes, among other newspapers, the Toronto Star, which is Canada's largest daily newspaper. The book publishing segment of the company consists of Harlequin Enterprises Limited, best known for publishing romance fiction worldwide. Before his appointment in 1982 as President and Chief Executive Officer for Harlequin, Mr. Galloway was a founding partner of the Canada Consulting Group, a leading strategic management consulting firm, which was acquired by Boston Consulting Group in 1992. He began his career with General Foods. Mr. Galloway also serves as a director of Abitibi Consolidated, The E.W. Scripps Company and Toromont Industries Ltd.

Ida J. Goodreau (3) (4)
Vancouver, British Columbia

Chair of the Pension Subcommittee

On the Board of Directors since April 24, 2003.

Ms. Goodreau has been President and Chief Executive Officer of Vancouver Coastal Health Authority since 2002. The Vancouver Coastal Health Authority shares responsibility with five other geographical health authorities and ministries of the British Columbia provincial government for planning, delivering, monitoring and evaluating health care programs in the province. From 2000 to 2002, Ms. Goodreau was Senior Vice President of Global Optimization & Human Resources, Norske Skog Industries.

Member of the:

(1) *Audit Committee*

(2) *Reserves Committee*

(3) *Management Resources and Compensation Committee*

(4) *Pension Subcommittee*

(5) *Nominating and Governance Committee*

(6) *Health, Safety, Environment & Social Responsibility Committee*

(7) *Special Committee (formed to evaluate the offer received from Royal Dutch Shell plc, the Company's majority shareholder)*

Kerry L. Hawkins [1] [5] [7]
Winnipeg, Manitoba

Chair of the Audit Committee

On the Board of Directors since October 1, 1997.

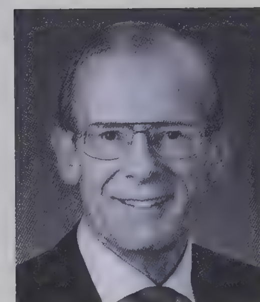
Mr. Hawkins was President of Cargill Limited from 1982 until his retirement at the end of November 2005. Cargill Limited is a Canadian agricultural, food and processing company. Mr. Hawkins also serves as a director of TransCanada Pipelines Limited, TransCanada Corporation and Nova Chemicals Corporation.

David W. Kerr [1] [2] [5] [7]
Toronto, Ontario

Chair of the Reserves Committee

On the Board of Directors since April 24, 2003.

Mr. Kerr has served as a director of Brookfield Asset Management Inc. since May 1987. Until its acquisition by Xstrata in November 2006, Mr. Kerr was the Chairman and a director of Falconbridge Limited (formerly Noranda Inc.). Falconbridge Limited was a leading international mining and metals company and was one of the world's largest producers of zinc and nickel and a significant producer of copper, primary and fabricated aluminum, lead, silver, gold, sulphuric acid and cobalt. Mr. Kerr was the Chairman and a director of Noranda Inc. from 2002 to 2006, Chairman and Chief Executive Officer from 2001 to 2002 and President and Chief Executive Officer from 1990 to 2001. Mr. Kerr also serves as a director Sun Life Financial Inc.



Clive Mather
Calgary, Alberta

On the Board of Directors since August 1, 2004.

Mr. Mather has served as President and Chief Executive Officer of Shell Canada Limited since August 2004. From 2002 to 2004, Mr. Mather served as Chairman of Shell UK Limited and Head of Global Learning of Shell International Limited. From 2001 to 2002, Mr. Mather served as Special Advisor to the Chairman of the Committee of Managing Directors of Shell International Limited. From 1999 to 2001, Mr. Mather served as Chief Executive Officer of Shell Services International Ltd. Prior to this, Mr. Mather served as Director, International of Shell International Limited. Mr. Mather is also currently a director of Shell Chemicals Canada Ltd., Shell Canada Products Limited and Shell Canada OP Inc. Mr. Mather served on the Board of Directors of Placer Dome Inc. from April 2005 to January 2006.

Member of the:

(1) *Audit Committee*

(2) *Reserves Committee*

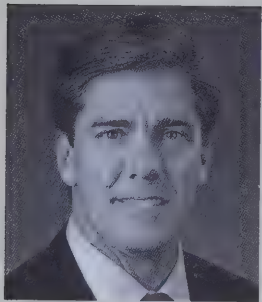
(3) *Management Resources and Compensation Committee*

(4) *Pension Subcommittee*

(5) *Nominating and Governance Committee*

(6) *Health, Safety, Environment & Social Responsibility Committee*

(7) *Special Committee (formed to evaluate the offer received from Royal Dutch Shell plc, the Company's majority shareholder)*



Marvin E. Odum
Houston, Texas

On the Board of Directors since April 28, 2006.

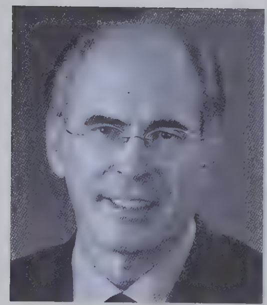
Mr. Odum has been Executive Vice President – Americas for Shell Exploration and Production since May 2005. Prior to that, from May 2003 to May 2005, Mr. Odum was Chief Executive Officer of InterGen, a global power generation company active in 13 countries. Mr. Odum was Shell Gas and Power Director for the Americas, based in London from 2001 to 2003.

Ronald W. Osborne (1) (3) (4) (7)
Toronto, Ontario

Chair of the Management Resources and Compensation Committee

On the Board of Directors since April 25, 2001.

Since May 2005, Mr. Osborne has been Chairman of the Board of Sun Life Financial Inc. and its wholly owned subsidiary, Sun Life Assurance Company of Canada. From 1999 to 2003, Mr. Osborne was President and Chief Executive Officer of Ontario Power Generation Inc., which owns the power generation assets supplying approximately 85 per cent of all electricity consumed in Ontario. Mr. Osborne is also a director of Torstar Corporation, St. Lawrence Cement Group Inc., Massachusetts Financial Services Company and Four Seasons Hotels Inc., and is a trustee of RioCan Real Estate Investment Trust.

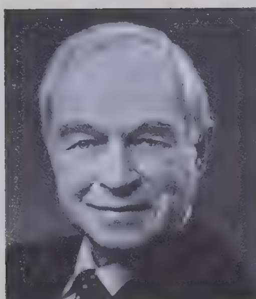


Rob Routs
The Hague, the Netherlands

Chairman of the Meetings of the Board

On the Board of Directors since April 29, 2005.

Mr. Routs is currently an Executive Director of Royal Dutch Shell plc and was previously a Managing Director of the Royal Dutch/Shell Group since 2003. From 2002 to 2003, Mr. Routs served as President and Chief Executive Officer of Shell Oil Products U.S., President of Shell Oil Company and Country Chair for the Shell Group in the United States. From 2000 to 2002, Mr. Routs served as President and Chief Executive Officer of Equilon Enterprises LLC. Prior to that, Mr. Routs was Head of Shell International Resource and Technology Services Group (Shell Global Solutions).



Raymond Royer, O.C. [2] [4]
Île-Bizard, Quebec

On the Board of Directors since April 26, 2000.

Mr. Royer has been President and Chief Executive Officer of Domtar Inc. since 1996. Domtar Inc. is a North American manufacturer of fine papers, pulp and forest products. Mr. Royer also serves as a director of Domtar Inc. and Power Financial Corporation.

Nancy C. Southern [5] [6]
Calgary, Alberta

Chair of the Health, Safety, Environment & Social Responsibility Committee

On the Board of Directors since April 25, 2001.

Ms. Southern has been President and Chief Executive Officer of ATCO Ltd. and Canadian Utilities Limited since January 2003. Ms. Southern was Co-Chairman and Chief Executive Officer of ATCO Ltd. and Canadian Utilities Limited from 2000 to December 2002. ATCO Ltd. is a management holding company with operating subsidiaries engaged in regulated natural gas and electric operations, power generation, manufacturing, sale and leasing of relocatable workforce shelter products and other businesses. Canadian Utilities Limited is a holding company with operating subsidiaries engaged in natural gas and electrical energy utility operations and in related non-regulated operations. Ms. Southern also serves as a director and Chief Executive Officer of certain other subsidiaries of ATCO Ltd. and Canadian Utilities Limited. Ms. Southern is a director of the Bank of Montreal and Akita Drilling Ltd. and is Executive Vice President of Spruce Meadows.

Member of the:

[1] *Audit Committee*

[2] *Reserves Committee*

[3] *Management Resources and Compensation Committee*

[4] *Pension Subcommittee*

[5] *Nominating and Governance Committee*

[6] *Health, Safety, Environment & Social Responsibility Committee*

[7] *Special Committee (formed to evaluate the offer received from Royal Dutch Shell plc, the Company's majority shareholder)*

Corporate Governance Practices

Shell Canada believes that sound corporate governance practices contribute to the effective management of the Company and the achievement of its goals.

The Company's corporate governance practices are aligned with the standards of the Canadian Securities Administrators set forth in National Instrument 58-101 *Disclosure of Corporate Governance Practices* and National Policy 58-201 *Corporate Governance Guidelines.* A complete description of the Company's approach to corporate governance is contained in its *Statement of Corporate Governance Practices* attached as Schedule VI to the Annual Information Form, dated March 8, 2007.

Key Practices

Key aspects of Shell Canada's approach to corporate governance are:

- appointment of a Lead Director;
- an independence policy for directors;
- 100 per cent independence of all committees of the board (no officer or employee representing the Company or its majority shareholder may sit on these committees);
- the board and committees hold sessions without management present and separate meetings of the independent directors are held in connection with all board meetings;
- annual reviews of written charters for the board and committees;
- annual reviews of written position descriptions for the Chairman of the Meetings of the Board, the Lead Director, the directors and the chairs of the committees;
- requirement for all independent directors and Shell Canada's President and Chief Executive Officer to hold shares in the Company equal to three years' board annual retainer fees (currently $50,000 per year) after five years of board service;
- regular evaluations by the board of its effectiveness;
- orientation and continuous education in the businesses of Shell Canada available to all members of the board, including the annual release of the Directors' Handbook;
- a robust director recruitment process which, in 2006, led to the appointment of two additional independent directors;
- board approval of Shell Canada's strategic plans;
- annual review of the adequacy and form of compensation of directors (including minimum share ownership requirements) by the Nominating and Governance Committee;
- three financial experts on the Audit Committee;
- annual review of succession planning and talent by the Management Resources and Compensation Committee;
- annual review of the performance of Shell Canada's Chief Executive Officer and annual approval of his and other senior executives' compensation by the Management Resources and Compensation Committee;
- application of a *Code of Ethics* and *Statement of General Business Principles* (which is available at **www.shell.ca**) to all directors, officers and employees;
- a Corporate Disclosure Policy that describes and governs the Company's corporate disclosure practices;
- procedures for reporting accounting or auditing concerns or complaints to the Audit Committee; and
- systems that allow shareholders, employees and other members of the public to communicate with the Board of Directors, management, the Chief Compliance Officer or the Ombuds office.

Board of Directors

The Board of Directors is responsible for overseeing the business and affairs of Shell Canada in a stewardship role. The day-to-day management is delegated to the officers of the Company. Any responsibilities that have not been delegated to the officers or to a committee of the Board remain with the Board.

The Board is composed of 12 Directors. Nine of the Directors are independent and have no material relationship with either the Company or its majority shareholder. The Board reviews its composition and size once a year and believes this fairly reflects the investment of minority shareholders.

The Board holds six regularly scheduled meetings each year, plus special Board meetings as required from time to time. Shell Canada's bylaws state that the quorum for any meeting of the Board shall be two Directors.

Committees

The Board of Directors has established the following committees:

- Audit Committee
- Reserves Committee
- Management Resources and Compensation Committee
- Pension Subcommittee
- Nominating and Governance Committee
- Health, Safety, Environment & Social Responsibility Committee
- Special Committee (to evaluate the offer received from Royal Dutch Shell plc, the Company's majority shareholder)

Only independent Directors sit on these committees. Each committee member knows the mandate of the committee on which he or she serves and conducts activities that are consistent with and fulfil the committee's mandate.

The charters of the Board and its customary committees can be found on the Company's website at **www.shell.ca**.

Selection of Directors

The shareholders of Shell Canada elect the Board of Directors each year at the annual meeting of shareholders. The Nominating and Governance Committee recommends new appointments and reappointments to the Board for consideration by the shareholders.

In 2006, the Committee identified two new Directors to join the Board. Louise Fréchette and David Galloway were chosen following an extensive search conducted by management and a recruitment firm engaged by the Committee. A short list of candidates was selected following a search of the Canadian and international markets, and these individuals were interviewed by both the Chief Executive Officer and a member of the Committee. The results of these interviews were reviewed with the Committee as a whole, and the final preferred candidates were recommended to the Board for approval. The Board approved the appointment of these new Directors effective September 28, 2006.

Also in 2006, the Nominating and Governance Committee considered whether to adopt a policy on majority voting in Director elections. The Committee concluded that such a policy would not be adopted by Shell Canada due to its ownership structure, of which Royal Dutch Shell plc currently owns 78 per cent of the Company's common shares.

A Director must retire at the next annual meeting of shareholders following his or her 70th birthday.

Chairman of the Meetings of the Board and Lead Director

Mr. Robert J. Routs serves as Chairman of the Meetings of the Board. Mr. Routs is a member of the executive committee of Royal Dutch Shell plc (the Company's majority shareholder) and therefore is not an independent Director. To complement this role, the Board appointed Mr. Derek H. Burney, an independent Director, as Lead Director in March 2005.

The Chairman of the Meetings of the Board is expected to:

- consult with the President and Chief Executive Officer and the Secretary of the Company to determine the dates and locations of meetings of the Board and the shareholders;
- require the Board to meet at least six times annually and as many more times as necessary for the Board to carry out its duties and responsibilities effectively;
- ensure that all the required business is brought before a meeting of shareholders;
- in consultation with the President and Chief Executive Officer and the Secretary of the Company, review the meeting agendas to ensure all required business is brought before the Board to enable the Board to carry out its duties and responsibilities;
- attend all meetings of the Board and the shareholders except as otherwise authorized by the bylaws;
- ensure the Board has the opportunity to meet separately without management present at all meetings;
- provide leadership to enable the Board to act as an effective team in carrying out its duties and responsibilities; and
- advise, counsel and mentor the President and Chief Executive Officer and fellow members of the Board.

The Lead Director is expected to:

- ensure that the Board functions independently of management of the Company;
- ensure that independent Directors have adequate opportunities to meet without management present;
- chair separate meetings of the independent Directors;
- represent the independent Directors in communications with shareholders, as appropriate;
- be available to Directors who have concerns that cannot be addressed by the Chairman of the Meetings of the Board; and
- perform such other functions as may be reasonably requested by the Board or the Chairman of the Meetings of the Board.

Board Evaluations

The Chairman of the Nominating and Governance Committee conducts an annual assessment of the Board, individual Directors, the Chairman of the Meetings of the Board and the chairs of the committees. He then prepares a summary report for the Board. The assessment includes:

- measuring performance against key responsibilities, including strategy, succession planning, performance management, compliance, financial oversight and risk management; and
- assessing Board resources and capabilities, including knowledge, contribution of fellow Directors, information, authority and time.

Shell Canada believes this annual assessment is a constructive means to assess the effectiveness of the Board and to formulate recommendations for improvement.

Director Education

New Board members receive a comprehensive orientation that includes a tour of some of Shell Canada's major operating facilities. All new Directors receive a manual containing the charters of the Board and its committees and other relevant corporate, policy and business information. The chairs of the committees provide regular reports to the Board on activities completed by each committee. Senior management makes regular presentations to the Board on the main areas of the Company's business.

Shell Canada offers a continuing education program for its Directors, which focuses on Shell Canada's business and corporate governance practices. Some aspects of Shell Canada's continuing education program for Directors include:

- special sessions conducted regularly by members of senior management on their individual areas of expertise;
- membership for each Director in an organization dedicated to improving the profession of directorship in Canada; and
- tours of Shell Canada's major operating facilities and discussions with the President and Chief Executive Officer regarding areas of specific interest.

Meeting Procedures

The President and Chief Executive Officer establishes the agenda for each Board meeting in collaboration with the Chairman of the Meetings of the Board. All meeting materials for both the Board and the committees are distributed approximately one week in advance of the respective meetings to provide the Board with sufficient time to review and prepare for the Directors' and committee meetings.

Access to Management and Outside Advisers

All Directors have access to management of the Company. Directors may hire outside advisers at the Company's expense, subject to the approval of the Nominating and Governance Committee. Each committee is authorized to retain outside advisers.

Communication with Shareholders

Any shareholder is invited to contact the Board by e-mail at **corporatesecretary@shell.com** or in writing to:

Board of Directors
Shell Canada Limited
Shell Centre
6th Floor, 400 – 4th Avenue S.W.
Calgary, Alberta, Canada T2P 0J4
Attention: Secretary

The Secretary will review each communication and determine the appropriate action to be taken with the Board or any of its committees.

Investor Information

SHELL CANADA LIMITED

(incorporated under the laws of Canada)

HEAD OFFICE

Shell Centre
400 – 4th Avenue S.W.
Calgary, Alberta, Canada T2P 0J4
Telephone (403) 691-3111
Website www.shell.ca

TRANSFER AGENT AND REGISTRAR

CIBC Mellon Trust Company
P.O. Box 7010 Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9
E-mail inquiries@cibcmellon.com
Website www.cibcmellon.com
Facsimile (416) 643-5501
Answerline (416) 643-5500 or
1-800-387-0825
Toll-free throughout North America

STOCK EXCHANGE LISTINGS

The common shares of Shell Canada Limited are listed on the Toronto Stock Exchange (stock symbol SHC) and do not have an established public trading market in the United States.

DUPLICATE REPORTS

Shareholders who receive more than one copy of Shell Canada's Interim Reports and the Annual Report as a result of having their shareholdings represented by two or more share certificates may wish to contact the transfer agent to have their holdings consolidated. It will not be necessary to forward share certificates.

ANNUAL INFORMATION FORM AND 2006 SUSTAINABLE DEVELOPMENT REPORT

The Corporation's Annual Information Form for 2006 and the *2006 Sustainable Development Report* are available to shareholders on request from the Corporation's Secretary at Shell Canada's head office.

OWNERSHIP AND VOTING RIGHTS OF SHELL CANADA LIMITED

(as at December 31, 2006)

Shell Canada is a Canadian corporation. Ownership of the Company is divided between public shareholders (approximately 22 per cent) and Shell Investments Limited (approximately 78 per cent). Shell Investments Limited is owned by Shell Petroleum N.V., which, in turn, is owned by Royal Dutch Shell plc, an English company with headquarters in the Netherlands.

APPROXIMATE CONVERSION FACTORS

1 cubic metre of liquids	= 6.29 barrels
1 cubic metre of gases	= 35.3 cubic feet
1 barrel of oil equivalent	= 6,000 cubic feet of gases
1 tonne	= 2,205 pounds
	= 0.984 long ton
	= 1.102 short tons
1 kilometre	= 0.621 mile
1 hectare	= 2.47 acres
1 litre	= 0.22 gallon

Printed in Canada by Sundog Printing, this report uses FSC Certified paper for both text and cover pages. The FSC paper, paper mills and printer are certified by the Forest Stewardship Council, an international network promoting environmentally appropriate and socially beneficial management of the world's forests.

The report was produced in a printing facility that produces nearly zero volatile organic compound (VOC) emissions. Sundog Printing's certification number is SW-COC-1715.

The text and cover pages of this annual report have been printed with vegetable-based inks on Productolith Dull paper, which contains 10 per cent post-consumer waste. The financial pages have been printed on Mohawk Via Felt Bright White paper, which contains 30 per cent post-consumer waste. The Via line of paper is produced through Green-E certified renewable wind-generated electricity, resulting in nearly zero VOC emissions.

For Information:

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www.shell.ca

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